Independent Report on Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's 2021 Avoided Cost Proceeding

(Docket Nos. 2021-89-E and 2021-90-E)

prepared for the Public Service Commission of South Carolina

August 23rd, 2021

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List of acronyms

AEO	Annual Energy Outlook
APPA	American Public Power Association
CAGR	Compound Annual Growth Rate
CCEBA	Carolinas Clean Energy Business Association
CCL	South Carolina Coastal Conservation League
CT	Combustion Turbine
DCA	South Carolina Department of Consumer Affairs
DEC	Duke Energy Carolinas LLC
DEP	Duke Energy Progress LLC
DR	Data Request
EEI	Edison Electric Institute
EIA	US Energy Information Administration
FERC	Federal Energy Regulatory Commission
FOM	Fixed Operating and Maintenance

IRP	Integrated Resource Plan
ISO	Independent System Operator
JDA	Johnson Development Associates
LCOE	Levelized Cost of Electricity
LEI	London Economics International LLC
LEO	Legally Enforceable Obligation
LOLE	Loss of Load Expectation
MW	Megawatt
NARUC	National Association of Regulatory Utility Commissioners
NOC	Notice of Commitment
NRECA	National Rural Electric Cooperative Association
ORS	Office of Regulatory Staff
PAF	Performance Adjustment Factor
PFE	Price Forecasting Error
PPA	Power Purchase Agreement
PURPA	Public Utility Regulatory Policies Act of 1978
PV	Photovoltaic
PV	Present Value
QF	Qualifying Facility
RA	Resource Adequacy
RFP	Request for Proposals
SACE	Southern Alliance for Clean Energy
SC PSC	Public Service Commission of South Carolina
SEIA	Solar Energy Industries Association
SISC	Solar Integration Services Charge
TOU	Time-of-use
VOM	Variable Operating and Maintenance
VoSC	Value of Solar Capacity
WACC	Weighted Average Cost of Capital

1 Executive summary

London Economics International LLC ("LEI") was retained by the Public Service Commission of South Carolina ("SC SPC" or "the Commission") to serve as an independent expert in the following avoided cost proceedings:

- Docket No. 2021-88-E – Dominion Energy South Carolina, Inc.'s 2021 Avoided Cost Proceeding Pursuant to South Carolina Code Section 58-41-20(A);
- Docket No. 2021-89-E – Duke Energy Carolinas, LLC ("DEC")'s 2021 Avoided Cost Proceeding Pursuant to South Carolina Code Section 58-41-20(A); and
- Docket No. 2021-90-E – Duke Energy Progress, LLC ("DEP")'s 2021 Avoided Cost Proceeding Pursuant to South Carolina Code Section 58-41-20(A).

This Independent Report provides LEI's independently derived conclusions following a review of the avoided cost rates, methodology, terms, calculations, and conditions proposed by DEC and DEP (collectively "the Companies") in Docket Nos. 2021-89-E and 2021-90-E. The report is structured as follows:

Section 2 provides the reader with context regarding LEI's role in the current proceeding. The section begins with a discussion of the scope of work as ordered by the Commission in Order No. 2021-520. LEI then provides an overview of the South Carolina Energy Freedom Act, or Act No. 62, which established the procedural framework that governs this proceeding, and determined the Commission's overarching objectives in approving avoided cost applications. The section also briefly reviews the Public Utility Regulatory Policies Act of 1978, which set out the arrangements by which qualifying facilities ("QFs") transact with electric utilities, and importantly, introduced the notion of avoided cost.

Section 3 summarizes the key filings submitted in Docket Nos. 2021-89-E and 2021-90-E, focusing on the filings that were subsequently entered into the hearing record. LEI discusses the notable updates or changes proposed by the Companies relative to the 2019 avoided cost proceeding, as well as the modifications that were ultimately agreed to by the parties that entered into the Stipulation of Agreement filed with the Commission on July 23rd, 2021.

Section 4 reviews the quantitative analysis that LEI conducted to verify the reasonableness of the avoided cost methodology, calculations, and resulting rates proposed by the Companies. This analysis comprised of two phases: first, to verify the proposed avoided capacity costs, LEI developed its own estimates of the current cost of entry for a peaking facility using publicly available data; and second, to verify the proposed avoided energy costs, LEI deployed its proprietary electricity market dispatch model, POOLMod (described in Appendix A), to simulate a base case and change case. The goal of this analysis was not to develop an exact replica of the rates put forth in the Stipulation, but rather to determine whether the proposed rates fall within a reasonable range estimated by LEI using a set of credible assumptions.

Section 5 evaluates the proposed changes to the terms and conditions included in DEC and DEP's standard offer, form contract, and commitment to sell form. The Stipulation proposes only limited modifications to the contracts since the versions approved by the Commission in the previous avoided cost proceeding. LEI evaluates whether the changes could be deemed as being commercially reasonable as required under Act No. 62.

Section 6 concludes by discussing LEI's observations from its review of the filings in the current proceeding, and summarizing LEI's final opinion consistent with the language of the law.

- Ultimately, following the quantitative analysis of DEC and DEP's avoided cost methodology, LEI finds that the ***proposed avoided costs and rates lie within 5% of our own internal estimates, which we view as falling within a zone of reasonableness***.
- LEI also finds the ***proposed modifications to the Companies' contract documents to be commercially reasonable***, as they primarily act to increase flexibility for QFs, and in some instances were requested by them.
- In addition, given the participation of diverse stakeholders in the proposed Stipulation (where the Stipulating Parties include organizations representing the public interest as well as the interests of developers), ***LEI views the settlement as balanced***.

For these reasons, and as discussed in further detail in the remainder of this report, **LEI recommends that the Commission approve the proposed Stipulation**.

2 Introduction

2.1 Scope of work

LEI was engaged by the SC PSC on July 29th, 2021,[1] to act as a qualified, independent third-party consultant in Docket Nos. 2021-89-E and 2021-90-E – the 2021 avoided cost proceedings of DEC and DEP, respectively.

As part of this engagement, LEI has been retained to conduct the following tasks:

- observe the hearing that was held on August 2nd, 2021;
- review all submissions filed electronically on the SC PSC's Docket Management System, including all pre-filed testimony and settlement testimony, and focusing specifically on the evidence entered into the hearing record;
- verify the avoided cost methodology and calculations contained within the Stipulation of Agreement entered into between DEC, DEP, and several other parties to the dockets, as well as the Stipulation Testimony; and
- write and file this Independent Report on the Stipulation of Agreement.[2]

Following the submission of this Independent Report with the Commission, LEI understands that the firm will be required to respond to any discovery from parties regarding the report. In addition, LEI may be requested to testify and be cross-examined before the Commission at the hearing currently scheduled for September 16th – 17th, 2021.

It is important to note that the scope of work as outlined by the Commission also allowed LEI to "*[i]f necessary, file data requests with the Parties.*"[3] However, the time between the date of LEI's engagement and the filing date of this report did not allow for sufficient time to submit data requests and receive and adequately review responses.[4,5] Notwithstanding this, LEI has made

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[1] SC PSC. *Statements of Award (Contract Nos. 4400026690 and 4400026691).* July 28, 2021.

[2] SC PSC. *Order No. 2021-520 Setting Third-party's Consultant's Scope of Work and Related Deadlines (Docket Nos. 2021-88-E, 2021-89-E, and 2021-90-E).* July 29, 2021.

[3] Ibid.

[4] It is LEI's understanding that data or discovery requests are typically submitted with twenty days' notice (see for example South Carolina Department of Consumer Affairs' first set of interrogatories and request for production to DEC and DEP, filed on May 12th, 2021, which states "*[r]esponses to these requests should be provided to the undersigned, via email, within twenty (20) days of the date of service*"). LEI was unable to execute an engagement letter before August 3rd, 2021, and was required to submit this Independent Report on August 23rd, 2021.

[5] Notably, Section 58-41-20(I) of the South Carolina Code requires that "*[t]he independent third party shall also include in the report a statement assessing the level of cooperation received from the utility during the development of the report and whether there were any material information requests that were not adequately fulfilled by the electrical utility.*" Given that LEI was unable to make data requests due to the compressed procedural timeline, we cannot assess the level of cooperation that would have been received from DEC and DEP.

reasonable assumptions in performing the aforementioned scope of work; we do not believe that our opinion would change had we been granted more time to make discovery requests.

2.2 Overview of Act No. 62

LEI was engaged by the Commission under Section 58-41-20(I) of the South Carolina Code, which authorizes the SC PSC to "*employ … third-party consultants and experts in carrying out its duties under this section, including, but not limited to, evaluating avoided cost rates, methodologies, terms, calculations, and conditions under this section.*"[6]

This section, namely Title 58, Chapter 41: *Renewable Energy Programs*, was added to the South Carolina Code as a result of the South Carolina Energy Freedom Act ("Act No. 62"), which was signed into law on May 16th, 2019. Importantly, Act No. 62 set forth the procedural framework which governs the SC PSC's avoided cost proceedings, requiring the Commission to regularly review and approve (at least once every two years) the avoided cost methodologies, standard offers, form contracts, and commitment to sell forms of electric utilities operating in the state. The legislation defines each of these items as follows:

- **avoided costs:** "*the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.*"[7] In addition to energy and capacity, ancillary services is also referenced as a component to be considered in each utility's avoided cost methodology;
- **standard offers:** contracts or power purchase agreements ("PPAs") between a utility and a small power producer with a qualifying facility ("QF") up to two megawatts ("MW") in size;
- **form contracts:** contracts or PPAs between a utility and a small power producer with a qualifying facility above 2 MW and up to 80 MW in size; and
- **commitment to sell forms:** a notice that is executed and submitted to a utility by a small power producer wishing to sell the output of its facility to the utility.

The avoided cost rates that are approved by the SC PSC through these proceedings ultimately feed into the standard offer PPA, which is made available to QFs on a fixed-price basis for a contract term of ten years. Section 58-41-20 of the South Carolina Code lays out the provisions of these avoided cost proceedings, which apply only to electric utilities serving more than 100,000 customers – namely Dominion Energy South Carolina, Inc., as well as the two Duke subsidiaries – DEC and DEP. In this way, the avoided cost proceedings determine the rates, terms, and conditions under which QFs transact with these utilities in the state.

Under the statutes, the SC PSC is required to initiate an avoided cost proceeding for each of these utilities at least once every two years, to ensure the proposed avoided cost methodologies,

[6] South Carolina Legislature. *South Carolina Code, Title 58, Chapter 41: Renewable Energy Programs.* May 16, 2019.

[7] Ibid.

standard offers, form contracts, and commitment to sell forms are "*just and reasonable to the ratepayers of the electrical utility, in the public interest, consistent with [the Public Utility Regulatory Policies Act of 1978 ("PURPA")] and the Federal Energy Regulatory Commission's implementing regulations and orders, and nondiscriminatory to small power producers; and shall strive to reduce the risk placed on the using and consuming public.*"[8]

In ensuring the nondiscriminatory treatment of small power producers, the Commission is directed to ensure that:

1. "*rates for the purchase of energy and capacity fully and accurately reflect the electrical utility's avoided costs*";
2. "*power purchase agreements, including terms and conditions, are commercially reasonable and consistent with regulations and orders promulgated by the Federal Energy Regulatory Commission implementing PURPA*"; and
3. "*each electrical utility's avoided cost methodology fairly accounts for costs avoided by the electrical utility or incurred by the electrical utility, including, but not limited to, energy, capacity, and ancillary services provided by or consumed by small power producers including those utilizing energy storage equipment. Avoided cost methodologies approved by the commission may account for differences in costs avoided based on the geographic location and resource type of a small power producer's qualifying small power production facility.*"[9]

It is with these overarching objectives in mind that LEI has conducted its analysis and review of the proposed Stipulation of Agreement, and the avoided cost methodology, rates and contract terms and conditions included therein.

2.3 Overview of PURPA

As discussed in Section 2.2, one of the key provisions of Act No. 62 requires the Commission to ensure that the proposed avoided cost methodologies, standard offers, form contracts, and commitment to sell forms are "*consistent with PURPA and the Federal Energy Regulatory Commission's implementing regulations and orders.*"[10] As such, before reviewing DEC and DEP's current application and discussing LEI's analysis of the evidence in the hearing record, it is important to briefly outline the requirements of PURPA that are relevant to this proceeding.

The Public Utility Regulatory Policies Act of 1978 ("PURPA"), specifically Sections 201 and 210, initially set out the arrangements by which QFs would transact with electric utilities. PURPA introduced the notion of avoided cost – i.e., pricing by reference to what the utility would otherwise pay to build and generate itself or purchase from another source.

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[8] Ibid.

[9] Ibid.

[10] Ibid.

As recognized by the Federal Energy Regulatory Commission ("FERC") in Order No. 69 regarding the implementation of PURPA, avoided costs can be broadly categorized into two components, namely energy- and capacity-related costs. Energy-related avoided costs are "*the variable costs associated with the production of electric energy (kilowatt-hours). They represent the cost of fuel, and some operating and maintenance expenses.*"[11] Capacity-related avoided costs are to do with infrastructure costs associated with building power plants, transmission, and distribution systems, or as stated by FERC, "*are the costs associated with providing the capability to deliver energy; they consist primarily of the capital costs of facilities.*"[12]

There are various approaches to evaluate these costs, from considering fixed values assumed for a new power plant, to modeling average or marginal system costs, or other market price-based methodologies. As recognized in the *PURPA Title II Compliance Manual* sponsored by the American Public Power Association ("APPA"), Edison Electric Institute ("EEI"), National Association of Regulatory Utility Commissioners ("NARUC"), and National Rural Electric Cooperative Association ("NRECA"), the following methods "*have generally satisfied FERC requirements and have been in use for many years*": (i) the proxy resource method; (ii) the peaker method; (iii) the revenue requirement differential method; (iv) fuel index rates; and (v) auction or request for proposals ("RFP") rates.[13] DEC and DEP's joint application seeks to continue using the peaker method to calculate their avoided cost rates – LEI discusses this approach in detail later in Section 4.

It is worth noting that FERC recently revised its regulations implementing Sections 201 and 210 of PURPA through a series of orders in 2020, namely Order No. 872, issued on July 16th, 2020, and Order No. 872-A, issued on November 19th, 2020.[14] These amendments primarily "*granted flexibility to state regulatory authorities in establishing avoided cost rates for [QF] sales inside and outside of the organized electricity markets.*"[15] However, as noted by DEC and DEP in their joint application, FERC's revised regulations have not factored into the Companies' current avoided cost application,[16] and as such are beyond the scope of this report.

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[11] FERC. *Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978 (Order No. 69, Docket No. RM79-55).* February 19, 1980.

[12] Ibid.

[13] Robert E. Burns and Kenneth Rose. *PURPA Title II Compliance Manual.* March 2014.

[14] FERC. *Addressing Arguments Raised on Rehearing and Clarifying Prior Order in Part (Order No. 872-A, Docket Nos. RM19-15-001 and AD16-16-001).* November 19, 2020.

[15] FERC. *FERC Affirms, Clarifies PURPA Final Rule.* November 19, 2020.

[16] *See* DEC and DEP. *Joint Application of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (Docket Nos. 2021-89-E and 2021-90-E).* April 22, 2021. P. 6: "*The Companies are continuing to evaluate how and/or whether to incorporate the new options available under Order No. 872, in light of Act 62's prescriptive requirements for PURPA implementation in South Carolina, and may propose changes in accordance with Order No. 872 in future PURPA-related proceedings.*"

3 Review of the proposed Stipulation of Agreement

The following section provides a review of the key filings submitted through the SC PSC's Docket Management System as part of DEC and DEP's 2021 avoided cost proceeding. LEI focuses mostly on the filings that were subsequently entered into the hearing record.[17] This overview will serve as background context for LEI's analysis, which includes a primarily quantitative analysis of the proposed avoided cost methodology and estimated rates (discussed later in Section 4), as well as an evaluation of the terms and conditions in DEC and DEP's proposed standard offer, form contract, and commitment to sell form (discussed later in Section 5).

3.1 DEC and DEP's joint application and direct testimony

DEC and DEP submitted their joint application to the Commission on April 22nd, 2021, outlining the proposed updates and changes to their avoided cost methodology, avoided cost rates, and contracts (i.e., the standard offer, form contract, and commitment to sell form) since those previously approved by the Commission in Docket Nos. 2019-185-E and 2019-186-E ("the 2019 avoided cost proceeding"). LEI summarizes the notable updates to each of these elements in Figure 1 below, which are described further in the subsections that follow.

Figure 1. Summary of DEC and DEP's joint application

Joint application element	Changes/updates since the 2019 avoided cost proceeding
Avoided cost methodology	• No change – continues using the peaker methodology
Avoided energy costs	• Eliminates DEC's summer AM on-peak pricing period, reducing total number of pricing periods for DEC from eleven down to ten
Avoided capacity costs	• Modifies DEC and DEP's capacity pricing periods to reflect the loss of load risk estimated in the 2020 Resource Adequacy Studies • Adjusts DEC and DEP's seasonal allocation weightings to 89% winter/11% summer and 100% winter/0% summer, respectively
Standard offer tariff, PPA, and terms and conditions	• Reflects the updated avoided energy and capacity costs • No change to non-rate related terms and conditions
Large QF tariff and PPA	• Modifies certain clauses to accommodate requests made by QFs: o Definition of change of control o Extends the testing period in cases where delays are caused by the Companies o Certain representations/warranties relating to "eligible commercial entity" and "eligible contract participant"
Notice of commitment to sell form	• No material changes proposed yet, although the Companies have committed to conducting a review alongside stakeholders

[17] The direct and surrebuttal testimonies of Matthew Stanley and John C. Ahlrichs, filed on behalf of Pelzer Hydro Company, LLC, Aquenergy Systems, LLC, and Northbrook Carolina Hydro, LLC ("the Hydro Intervenors") are outside of the scope of LEI's report because they were withdrawn from the record. The Hydro Intervenors requested and were granted permission to withdraw their petition to intervene, and as such are no longer parties to DEC and DEP's 2021 avoided cost proceeding.

DEC and DEP's joint application was supported by direct testimony and sponsored exhibits filed with the Commission on May 17th, 2021, from the following company representatives: Glen A. Snider, Director of Carolinas Integrated Resource Planning and Analytics; and David B. Johnson, Director of Business Development and Compliance. LEI references these testimonies and exhibits throughout the following subsections, to provide further context regarding the Companies' proposed updates.

3.1.1 Avoided cost methodology

DEC and DEP seek to continue using the same peaker methodology used and approved in the 2019 avoided cost proceeding to calculate the avoided cost rates proposed in the current proceeding. As discussed previously in Section 2.3, the peaker method is commonly used by utilities throughout the country to determine avoided costs, according to the *PUPRA Title II Compliance Manual*. Essentially, the premise of the peaker method, as implemented by DEC and DEP, is that it calculates the two avoided cost components as follows (see Section 4 for further details):

- **avoided energy costs:** this is based on the utility's forecasted avoided system marginal energy cost, and is estimated by modeling the utility's system on an hourly basis under a base case and a change case, over a ten-year time horizon. The base case models the utility's system as represented in the Companies' most recent integrated resource plans ("IRPs") and using current market assumptions, while the change case "*adds a hypothetical 100 MW of no-cost generation to the utility's generating fleet, which is available to the system in every hour of the ten-year period.*"[18] The resulting energy cost estimates from running production cost simulations under these two cases are then compared to approximate the avoided energy cost; and
- **avoided capacity costs:** this is based on the fixed capital, financing, and fixed operating costs of a simple-cycle combustion turbine ("CT" or "peaker") facility, which the utility is assumed to build and operate to meet customer demand if not for purchases from QF generators.

3.1.2 Avoided energy costs

DEC and DEP's proposed avoided energy cost rates estimated using the peaker methodology are outlined in Figure 2 and Figure 3 below.

In addition to these updated estimates, the Companies in their joint application also propose slight modifications to the avoided energy cost rate periods for DEC. Specifically, DEC seeks to remove the summer morning on-peak period that was approved in the 2019 avoided cost proceeding. Under the current proposal, DEC's summer on-peak period would thus no longer be divided between morning hours and afternoon/evening hours; instead, the morning hours would be captured in the summer off-peak period, while the afternoon/evening hours would be

[18] DEC and DEP. *Direct Testimony of Glen A. Snider on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (Docket Nos. 2021-89-E and 2021-90-E).* May 17, 2021. P. 25.

captured in a single summer on-peak period. DEC proposes this change because the energy credit rates estimated for the summer morning hours were not found to be materially different from those estimated for the summer off-peak hours.[19] This proposed change reduces DEC's total pricing periods from eleven down to ten. In contrast, the proposed pricing periods for DEP remain unchanged from the 2019 avoided cost proceeding, with a total of nine pricing periods.

Figure 2. DEC's proposed avoided energy cost rates under the joint application (cents/kWh)

	Interconnected to distribution			Interconnected to transmission		
Period	**Variable**	**Fixed 5-year**	**Fixed 10-year**	**Variable**	**Fixed 5-year**	**Fixed 10-year**
On-peak kWh						
Summer	3.01	3.03	3.20	2.87	2.89	3.06
Winter						
Morning hours	3.50	3.42	3.90	3.41	3.33	3.80
Evening hours	3.18	3.34	3.79	3.10	3.25	3.69
Premium peak						
Summer	3.01	3.06	3.19	2.90	2.94	3.08
Winter	4.78	4.52	4.72	4.63	4.38	4.57
Shoulder						
Morning/evening hours	3.18	3.17	3.21	3.12	3.11	3.15
Midday hours	2.62	2.73	2.76	2.57	2.68	2.71
Off-peak kWh						
Summer	2.16	2.22	2.31	2.12	2.18	2.27
Winter	3.08	3.02	3.25	3.02	2.96	3.18
Shoulder	2.38	2.25	2.33	2.35	2.22	2.30

Source: DEC and DEP. *Johnson DEC Exhibit 2 (Docket Nos. 2021-89-E and 2021-90-E)*. May 17, 2021. P. 8.

Figure 3. DEP's proposed avoided energy cost rates under the joint application (cents/kWh)

	Interconnected to distribution			Interconnected to transmission		
Period	**Variable**	**Fixed 5-year**	**Fixed 10-year**	**Variable**	**Fixed 5-year**	**Fixed 10-year**
On-peak kWh						
Summer	2.94	2.96	3.00	2.86	2.88	2.92
Winter						
Morning hours	3.75	3.61	3.92	3.68	3.54	3.84
Evening hours	3.65	3.76	4.27	3.57	3.68	4.18
Premium peak						
Summer	3.30	3.16	3.22	3.21	3.07	3.12
Winter	5.19	4.82	5.12	5.04	4.68	4.98
Shoulder	3.03	3.04	3.04	2.99	3.00	3.00
Off-peak kWh						
Summer	2.68	2.75	2.83	2.64	2.71	2.78
Winter	3.05	3.18	3.49	3.00	3.13	3.44
Shoulder	2.62	2.58	2.61	2.59	2.55	2.58

Source: DEC and DEP. *Johnson DEP Exhibit 2 (Docket Nos. 2021-89-E and 2021-90-E)*. May 17, 2021. P. 8.

[19] *See* DEC and DEP. *Snider DEC/DEP Exhibit 2 (Docket Nos. 2021-89-E and 2021-90-E)*. May 17, 2021. P. 1-2.

3.1.3 Avoided capacity costs

DEC and DEP's proposed avoided capacity cost rates estimated using the peaker methodology are outlined in Figure 4 and Figure 5 below.

Figure 4. DEC's proposed avoided capacity cost rates under the joint application (cents/kWh)

	Interconnected to distribution			Interconnected to transmission		
Period	Variable	Fixed 5-year	Fixed 10-year	Variable	Fixed 5-year	Fixed 10-year
On-peak kWh						
Summer	0.00	0.67	2.04	0.00	0.65	1.98
Winter	0.00	2.22	6.76	0.00	2.16	6.58

Source: DEC and DEP. *Johnson DEC Exhibit 2 (Docket Nos. 2021-89-E and 2021-90-E)*. May 17, 2021. P. 8.

Figure 5. DEP's proposed avoided capacity cost rates under the joint application (cents/kWh)

	Interconnected to distribution			Interconnected to transmission		
Period	Variable	Fixed 5-year	Fixed 10-year	Variable	Fixed 5-year	Fixed 10-year
On-peak kWh						
Winter	0.00	7.58	10.29	0.00	7.43	10.08

Source: DEC and DEP. *Johnson DEP Exhibit 2 (Docket Nos. 2021-89-E and 2021-90-E)*. May 17, 2021. P. 8.

In addition to these updated estimates, the Companies in their joint application also propose slight shifts to their capacity pricing periods to reflect the loss of load risk estimated in their 2020 Resource Adequacy Studies.[20] For example, DEC seeks to shift the summer capacity pricing period from the previous 4 p.m. – 8 p.m. block to 5 p.m. – 9 p.m. under the current application; DEC seeks to shift the winter capacity pricing period from the previous 6 a.m. – 9 a.m. and 6 p.m. – 9 p.m. blocks to a single period from 5 a.m. – 10 a.m.[21] Furthermore, DEP seeks to remove its summer capacity pricing period, and shift its winter pricing period from the previous 6 a.m. – 9 a.m. and 6 p.m. – 9 p.m. blocks to a single period from 4 a.m. – 9 a.m.[22]

Finally, the Companies propose adjustments to the seasonal allocation weightings for capacity payments based on the total capacity of solar facilities currently connected to the Companies' systems plus solar facilities with executed PPAs. As such, DEC seeks to shift its seasonal allocation from the previous 70% winter/30% summer split to 89% winter/11% summer under the current application.[23] DEP seeks to shift its seasonal allocation from 99% winter/1% summer to 100% winter/0% summer.[24]

[20] *See* DEC. *Duke Energy Carolinas Integrated Resource Plan, Attachment III: Duke Energy Carolinas 2020 Resource Adequacy Study*. September 1, 2020; and DEP. *Duke Energy Progress Integrated Resource Plan, Attachment III: Duke Energy Progress 2020 Resource Adequacy Study*. September 1, 2020.

[21] *See* DEC and DEP. *Snider DEC/DEP Exhibit 2 (Docket Nos. 2021-89-E and 2021-90-E)*. May 17, 2021. P. 8.

[22] Ibid.

[23] Ibid. P. 3.

[24] Ibid. P. 5.

3.1.4 Standard offer tariff, PPA, and terms and conditions

The avoided cost rates discussed previously in Section 3.1.2 and Section 3.1.3 feed into DEC and DEP's standard offer tariff, which the Companies call the *Schedule PP (SC) Purchased Power tariff*. QFs with facilities up to 2 MW in size are eligible to commit their energy and capacity to the Companies under these Schedule PP rates, which are available on either a variable basis, or under 5- or 10-year fixed term options.

Under the standard offer, eligible QFs are subject to the following documents/agreements: (i) the Schedule PP tariff; (ii) the Standard Offer PPA (*Power Purchase Agreement by a Qualifying Cogenerator or Small Power Producer*); and (iii) the Standard Offer Terms and Conditions (*Terms and Conditions for the Purchase of Electric Power*). Aside from the rate changes discussed previously in Section 3.1.2 and Section 3.1.3, these three documents remain largely unchanged from those approved by the Commission in the 2019 avoided cost proceeding.

It is worth noting that in addition to the avoided cost rates, the Schedule PP tariff includes the following charges:

- an **Administrative/Seller Charge** of $11.07/month for DEC and $8.05/month for DEP, which is intended to "*ensure that the cost of supporting and billing the purchase of power from QFs are appropriately recovered from the QF and not passed along to other customers as part of the retail cost of service*";[25]
- **power factor-related charges and adjustments**;
- an **Interconnection Facilities Charge** of no less than $25/month (unless the interconnection facilities consist of a meter only, in which case this minimum is waived), which is calculated "*based on 1.0 percent of the estimated original installed cost and rearrangement cost of all facilities, including metering, required to accept interconnection*";[26] and
- a **Solar Integration Services Charge** ("SISC") of $1.10/MWh for DEC and $2.39/MWh for DEP, which applies only to uncontrolled solar photovoltaic ("PV") generation facilities.[27] The SISC is designed to capture "*the current cost to provide the additional operating reserves or generation "ancillary services" needed to integrate increasing levels of solar QF generation into the DEC and DEP systems*."[28]

[25] DEC and DEP. *Direct Testimony of David B. Johnson on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (Docket Nos. 2021-89-E and 2021-90-E).* May 17, 2021. P. 8.

[26] DEC and DEP. *Johnson DEC Exhibit 4, Johnson DEP Exhibit 4 (Docket Nos. 2021-89-E and 2021-90-E).* May 17, 2021.

[27] The Companies define uncontrolled solar PV generation as "*solar generation where the Qualifying Facility does not demonstrate that its facility is capable of operating or does not contractually agree to operate, in a manner that reduces its average daylight volatility to 6% or less of its average daylight power output*." (Source: DEC and DEP. *Johnson DEC Exhibits 1 and 2, Johnson DEP Exhibits 1 and 2 (Docket Nos. 2021-89-E and 2021-90-E).* May 17, 2021)

[28] DEC and DEP. *Joint Application of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (Docket Nos. 2021-89-E and 2021-90-E).* April 22, 2021. P. 15.

These charges, including the SISC, are unchanged from those approved in the 2019 avoided cost proceeding. However, the methodology and inputs used to calculate the SISC are currently subject to an independent technical review. According to the Amended SISC Partial Settlement Agreement filed in the current dockets for informational purposes on July 29th, 2021, the Companies have committed to submitting the results of this review and any proposed revisions to the SISC to the Commission by August 1st, 2022.[29]

3.1.5 Large QF tariff and PPA

The form contract, which comprises the Companies' *Large QF tariff* and *Large QF PPA*, applies to eligible QFs with facilities above 2 MW and up to 80 MW in size. As required by Section 58-41-20(A) of the South Carolina Code, the Companies' Large QF PPA does not specify any pre-determined price or contract term, but rather acts as a starting point for contract negotiations.

The contract remains mostly unchanged since the version approved by the Commission in the 2019 avoided cost proceeding. The Companies propose only limited modifications "*to incorporate certain accommodations that have been requested by QFs contracting pursuant to [the Large QF PPA] over the past 18 months*."[30] Specifically, the Companies seek the following:

- to modify the **definition of Change of Control** to "*remove transfers typically done in connection with tax equity financing transactions where the seller retains operational control*";[31]
- to extend the **Testing Period** to "*allow QF Sellers additional time to complete testing where the delay in obtaining a final permit to operate was caused by the Companies and which is not the result of the QF Seller's acts or omissions*";[32] and
- to modify certain representations and warranties related to the **Eligible Commercial Entity** and **Eligible Contract Participant** to "*allow QF Sellers additional flexibility for their representation to be effective as of the commercial operation date*."[33]

Notably, the Companies anticipate making future modifications to the Large QF PPA to ensure alignment between the contract and their revised interconnection procedures.[34] These changes, if any, will be made in collaboration with interested stakeholders.

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[29] DEC and DEP. *Amended Partial Settlement Agreement (Docket Nos. 2019-185-E and 2019-186-E).* July 29, 2021.

[30] DEC and DEP. *Joint Application of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (Docket Nos. 2021-89-E and 2021-90-E).* April 22, 2021. P. 17.

[31] DEC and DEP. *Direct Testimony of David B. Johnson on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (Docket Nos. 2021-89-E and 2021-90-E).* May 17, 2021. P. 15.

[32] Ibid. P. 16.

[33] Ibid. P. 16.

[34] It is LEI's understanding that the Companies' South Carolina Generator Interconnection Procedures and Appendix Duke CS were approved by the Commission on June 18th, 2021, in Docket No. 2019-326-E (Order No. 2021-439). The Companies are now awaiting approval from FERC for the complementary revisions made to the

3.1.6 Notice of commitment to sell form

As described by the Companies in their joint application, the notice of commitment to sell ("NOC") form is "*intended to provide small power producer QFs with a Commission-approved non-contractual option to establish a [legally enforceable obligation ("LEO")] under PURPA separate from execution of a contractually-binding PPA.*"[35]

The Companies have not proposed any material changes to the NOC form in the current application. However, similar to DEC and DEP's commitment with regards to the Large QF PPA, the Companies anticipate making future modifications to the NOC form to ensure alignment with their revised interconnection procedures. These changes, if any, will be made in collaboration with interested stakeholders.

3.2 Direct testimony of ORS witness, Brian Horii

The Office of Regulatory Staff ("ORS") is the state agency charged with representing the public interest of South Carolina in cases before the Commission. As defined in Act 258, the public interest means "*the concerns of the using and consuming public with respect to public utility services, regardless of the class of customer, and preservation of continued investment in and maintenance of utility facilities so as to provide reliable and high-quality utility services.*"[36]

As part of the ORS' duties to represent the public interest, the agency has retained Brian Horii, Senior Partner at Energy and Environmental Economics, Inc., as its expert witness for the current avoided cost proceeding. Mr. Horii submitted direct testimony and exhibits on behalf of ORS on June 11th, 2021, to summarize the results of his review of the Companies' avoided cost application. Overall, Mr. Horii is generally in agreement with most aspects of DEC and DEP's proposal, as discussed further below.

First, Mr. Horii agrees with DEC and DEP's approach and proposed updates to their avoided energy costs, stating his "*review of the Companies' current and prior testimony and work papers indicates no methodological differences regarding those approved by the Commission in Order No. 2019-881(A).*"[37] With regards to DEC's proposal to reduce the total number of pricing periods from eleven down to ten, Mr. Horii "*confirmed that the change in the DEC [time of use ("TOU")] periods reasonably reflects the updated energy cost profile in DEC's service territory*."[38]

Furthermore, when reviewing the minor contract modifications proposed by DEC and DEP, Mr. Horii concludes that "*[t]he proposed language changes are predominantly "housekeeping" changes such*

Companies' Joint Open Access Transmission Tariff. (Source: DEC and DEP. *Stipulation of Agreement (Docket Nos. 2021-89-E and 2021-90-E).* July 23, 2021)

[35] DEC and DEP. *Joint Application of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (Docket Nos. 2021-89-E and 2021-90-E).* April 22, 2021. P. 20.

[36] ORS. *Fiscal Year 2019-2020 Accountability Report.* March 18, 2021. P. A-3.

[37] ORS. *Direct Testimony and Exhibits of Brian Horii (Docket Nos. 2021-89-E and 2021-90-E).* June 11, 2021. P. 7.

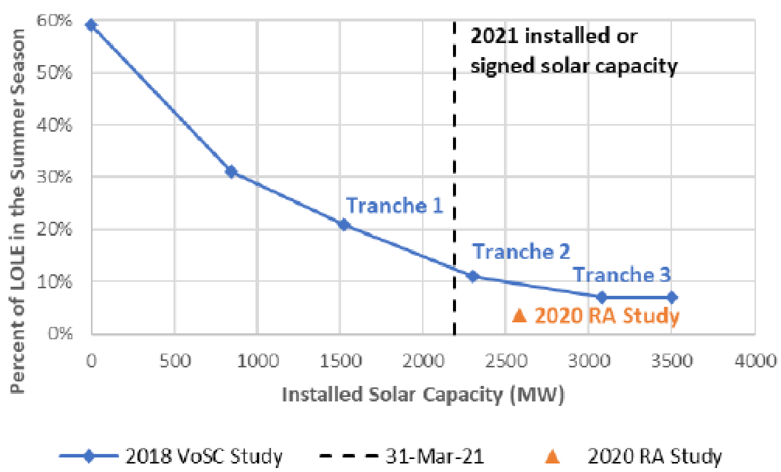
[38] Ibid. P. 8.

as header and footer changes" and finds "*the other very minimal changes to be reasonable and non-discriminatory to QFs.*"[39]

Mr. Horii also agrees with the Companies' approach and proposed updates to their avoided capacity costs, stating the approach "*follow[s] the methodology adopted by the Commission in Order No. 2019-881(A)*" and concluding that any updates made to the calculation inputs are "reasonable."[40] The only recommended change to the Companies' joint application relates to the proposed seasonal allocation of the avoided capacity costs for DEC. Specifically, Mr. Horii suggests "*that DEC's proposed 11% summer season allocation should be adjusted down to 5%*" to "*better [reflect] DEC's need for capacity in the summer as evidenced by the Company's most recent study of capacity need.*"[41]

Mr. Horii observes that DEC's approach to determining the seasonal allocation weighting relies on the results of its 2018 Value of Solar Capacity ("VoSC") Study, even though DEC has access to a more recent study (the 2020 Resource Adequacy ("RA") Study), which reflects updated assumptions and modeling improvements. In the joint application, DEC seeks to adjust its seasonal allocation for capacity payments based on the total capacity of solar facilities currently connected to its system plus solar facilities with executed PPAs – which amounts to 2,191 MW as of March 31st, 2021.[42] As discussed in Mr. Horii's testimony, DEC in its proposal chose to utilize the 2018 VoSC Study over the 2020 RA Study, as the 2018 VoSC Study (2,300 MW in Tranche 2) evaluated the loss of load expectation ("LOLE") for a level of solar installations that is more closely aligned with the current total capacity than the 2020 RA Study (2,579 MW) – see Figure 6.

Figure 6. Summer LOLE estimated under DEC's 2018 VoSC Study versus DEC's 2020 RA Study



Source: ORS. *Direct Testimony and Exhibits of Brian Horii (Docket Nos. 2021-89-E and 2021-90-E).* June 11, 2021.

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[39] Ibid. P. 17.

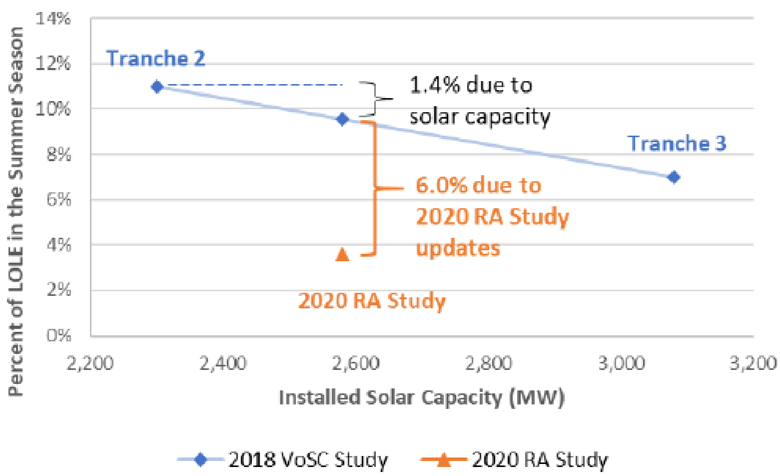
[40] Ibid. P. 11.

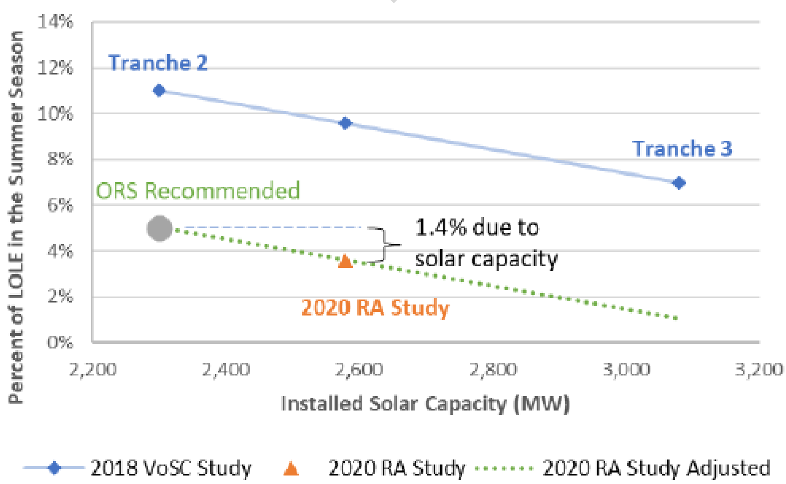
[41] Ibid. P. 11.

[42] Ibid. P. 12.

To address this concern of closely reflecting the current level of installed solar capacity, while also leveraging the updated assumptions and modeling improvements made in the 2020 RA Study, Mr. Horii develops the interpolation technique illustrated in Figure 7 below. As stated in his direct testimony, Mr. Horii recommends that "*instead of using the 2018 VoSC study Tranche 2 summer LOLE, the summer allocation should be calculated as the sum of the 3.6% summer LOLE from the 2020 RA study plus 1.4% to reflect that installed solar capacity in 2022 is expected to be lower than the installed solar capacity assumed in the 2020 RA study. This would result in a total summer LOLE of 5% (3.6% + 1.4%).*"[43]

Figure 7. Brian Horii's approach to calculating DEC's seasonal allocation





Source: ORS. *Direct Testimony and Exhibits of Brian Horii (Docket Nos. 2021-89-E and 2021-90-E)*. June 11, 2021.

[43] Ibid. P. 14.

3.3 Stipulation of Agreement and related stipulation testimony

On July 23rd, 2021, DEC and DEP filed a Stipulation of Agreement that was entered into by and between the Companies and other parties to the dockets, including ORS, the Carolinas Clean Energy Business Association ("CCEBA"),[44] the Southern Alliance for Clean Energy ("SACE"), and the South Carolina Coastal Conservation League ("CCL") (collectively the "Stipulating Parties"). Supporting stipulation testimony and exhibits from Mr. Snider and Mr. Johnson were also filed at this time.

It is important to note that the remaining parties to the dockets not included among the Stipulating Parties, namely the South Carolina Department of Consumer Affairs ("DCA") and Johnson Development Associates ("JDA"), have both reviewed the Stipulation. DEC and DEP in their filing letter accompanying the Stipulation note that "*[c]ounsel for the [DCA] has authorized the Companies to state that the [DCA] has no objection to the Stipulation*,"[45] while a letter filed with the Commission on behalf of JDA, dated July 27th, 2021, states that "*[s]ubject to the Commission's approval of the Stipulation, JDA does not intend to submit testimony, evidence or argument in these matters*."[46]

Overall, the Stipulating Parties agree to accept most aspects of DEC and DEP's joint application as initially filed with the Commission on April 22nd, 2021, and supported by the testimony and exhibits of Mr. Snider and Mr. Johnson filed on May 17th, 2021, with the following key modifications:

- **seasonal allocation for capacity payments:** DEC's avoided cost methodology, standard offer (Schedule PP) tariff, and Large QF tariff shall adopt the seasonal allocation for capacity payments as recommended by Mr. Horii and discussed previously in Section 3.2 (i.e., should reflect a weighting of 95% winter/5% summer instead of the 89% winter/11% summer split initially proposed by DEC in the joint application). DEC's updated avoided capacity cost rates as proposed under the Stipulation are shown in Figure 8 below, which replace the avoided capacity cost rates proposed in the joint application and shown previously in Figure 4;[47] and
- **minor amendments to the Large QF PPA:** the Large QF PPA shall adopt a new section defining **Permitted Transfer**, which clarifies "*certain actions that a QF Seller may take under*

[44] CCEBA is a non-profit trade association that focuses on "*promoting and advocating public policy positions supportive of solar power generation in North and South Carolina*." The organization represents over 50 members from across the clean energy sector, such as "*developers, manufacturing, engineering, construction, professional and financial services, and non-energy businesses wishing to pursue clean energy*." Members include, but are not limited to: Cypress Creek Renewables, EDF Renewables, First Solar, Google, NextEra Energy Resources, Pine Gate Renewables, and the Solar Energy Industries Association ("SEIA"). (Source: CCEBA. *Petition to Intervene (Docket Nos. 2021-89-E and 2021-90-E).* April 12, 2021.)

[45] DEC and DEP. *Stipulation of Agreement Filing Letter (Docket Nos. 2021-89-E and 2021-90-E).* July 23, 2021.

[46] JDA. *Letter to the Commission (Docket Nos. 2021-89-E and 2021-90-E).* July 27, 2021.

[47] DEC and DEP. *Stipulation of Agreement (Docket Nos. 2021-89-E and 2021-90-E).* July 23, 2021.

the Large QF PPA without triggering a Change of Control" and other minor wording corrections.[48]

Figure 8. DEC's proposed avoided capacity cost rates under the Stipulation (cents/kWh)

	Interconnected to distribution			Interconnected to transmission		
Period	Variable	Fixed 5-year	Fixed 10-year	Variable	Fixed 5-year	Fixed 10-year
On-peak kWh						
Summer	0.00	0.30	0.93	0.00	0.30	0.90
Winter	0.00	2.37	7.21	0.00	2.30	7.02

Source: DEC and DEP. *Johnson Stipulation Exhibit 2 (Docket Nos. 2021-89-E and 2021-90-E)*. July 23, 2021. P. 8.

As stated in the Stipulation, "*[t]he Parties agree to offer this Agreement to the Commission in its entirety as a comprehensive stipulation which is the product of extensive negotiations between the Parties. As such, the Parties agree to ask the Commission approve this comprehensive agreement in its entirety without exception, modification, or additional provisions. If the Commission declines to approve this agreement in its entirety, then any Party desiring to do so may withdraw from this agreement without penalty.*"[49]

As the Stipulation has been filed for Commission approval in the current proceeding, the remainder of LEI's Independent Report examines the avoided cost methodology and calculations (Section 4) and contract terms and conditions (Section 5) as presented in the Stipulation, as well as the accompanying supporting testimony and exhibits.

Specifically, Section 4 will analyze DEC and DEP's avoided cost rates (for energy and capacity) as proposed under the Stipulation – DEC's proposed avoided energy cost rates are the same as those presented in Figure 2 earlier, while the avoided capacity cost rates have been updated to reflect the adjustments resulting from Mr. Horii's recommended modification (as presented in Figure 8). DEP's proposed rates are the same as those presented in Figure 3 and Figure 5 earlier.

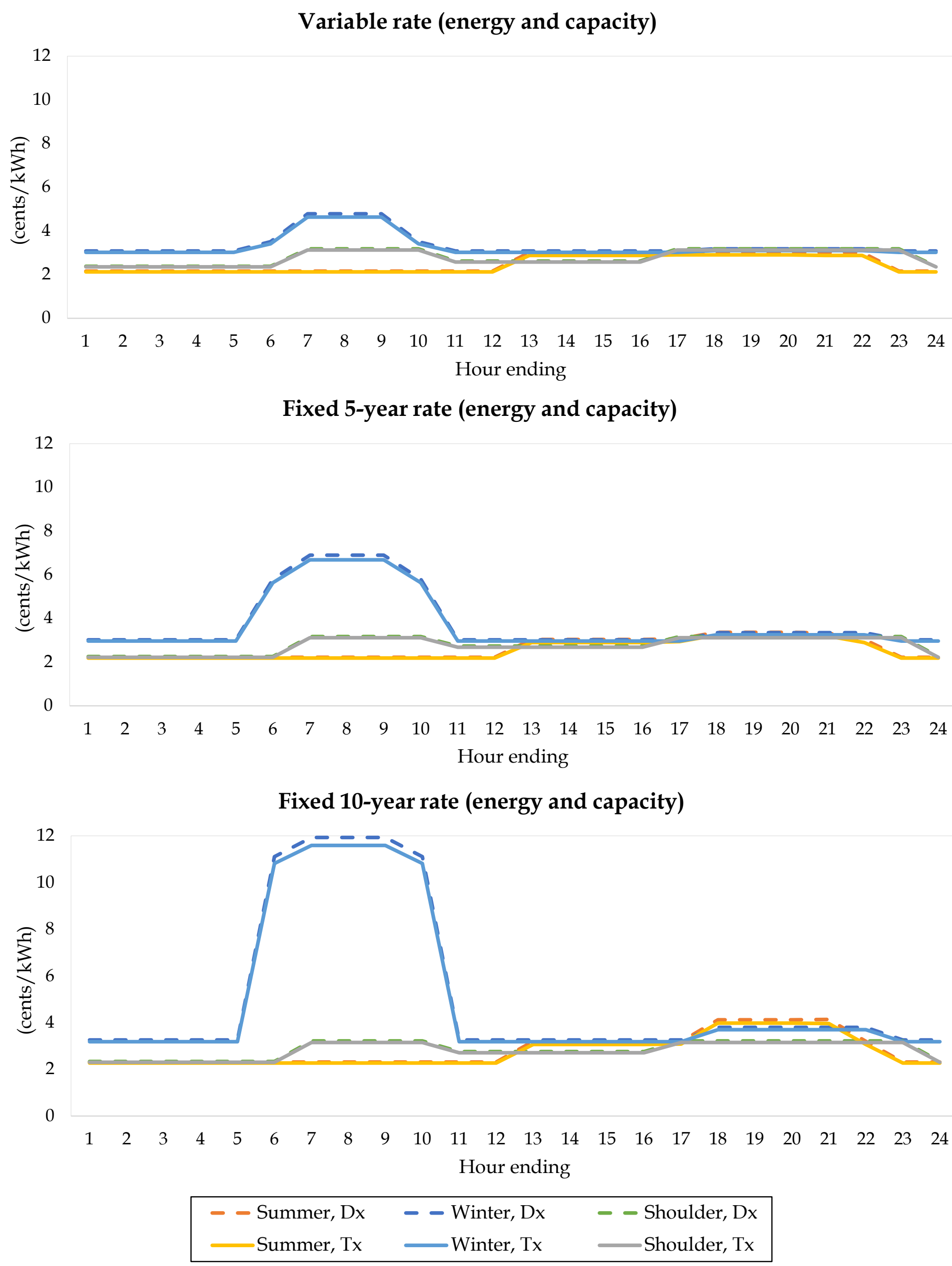
LEI presents DEC and DEP's proposed rates graphically on the following pages in Figure 9 and Figure 10, respectively. The charts demonstrate the maximum rates (including energy and capacity credits in cents/kWh) that eligible QFs would receive under the standard offer if generating in the summer, winter, and shoulder months, depending on their selection of either the variable, fixed 5-year, or fixed 10-year rates and the voltage level of interconnection to the Companies' systems. As shown in the figures, rates vary slightly depending on whether the QF is interconnected at the transmission (shown as solid lines) or distribution (shown as dotted lines) level, with distribution-connected rates marginally higher to recognize the avoidance of transmission system line losses. For DEC, rates for QFs interconnected at the distribution level are generally between 1% and 5% higher than those connected at the transmission level, depending on the time period and season; for DEP, the difference between distribution- and

[48] DEC and DEP. *Stipulation Testimony of David B. Johnson on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (Docket Nos. 2021-89-E and 2021-90-E)*. July 23, 2021.

[49] DEC and DEP. *Stipulation of Agreement (Docket Nos. 2021-89-E and 2021-90-E)*. July 23, 2021. P. 6.

transmission-interconnected rates ranges between 1% and 3%. LEI believes these differences are a reasonable reflection of line losses and other avoided costs.

Figure 9. DEC's proposed Schedule PP rates under the Stipulation (by type and season)

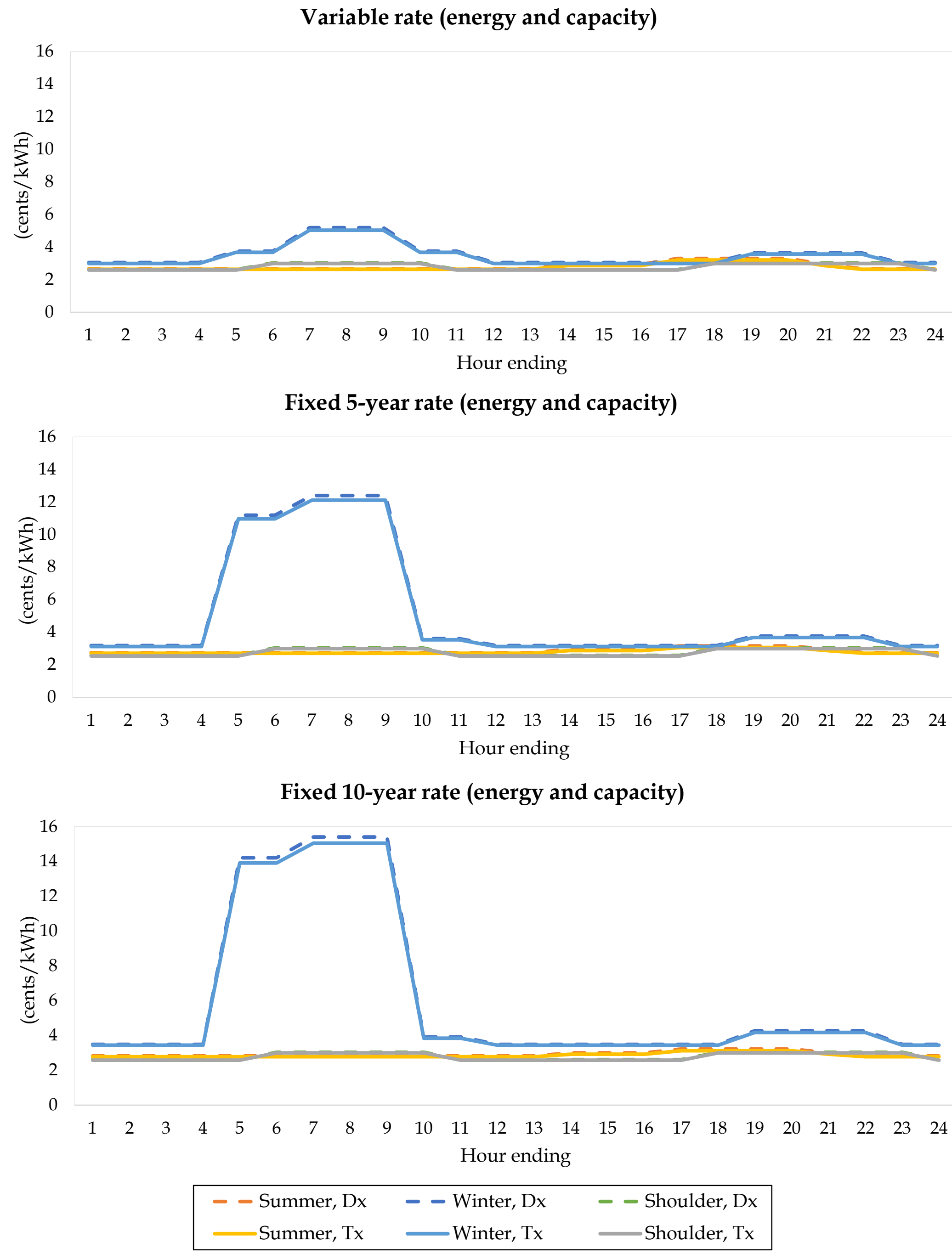


Note: For energy credits, summer months are defined as June-September, winter as December-February, and shoulder months as March-May and October-November. For capacity credits, summer months are July and August, winter months are December-March. As such, the chart shows summer and winter rates for months where the energy and capacity definitions overlap (e.g., July/August for summer, December-February for winter).

Dx = interconnected to distribution; Tx = interconnected to transmission

Source: DEC and DEP. *Johnson Stipulation Exhibit 2 (Docket Nos. 2021-89-E and 2021-90-E). July 23*, 2021. P. 8.

Figure 10. DEP's proposed Schedule PP rates under the Stipulation (by type and season)



Note: For energy credits, summer months are defined as June-September, winter as December-February, and shoulder months as March-May and October-November. For capacity credits, winter months are December-March. As such, the chart shows winter rates for months where the energy and capacity definitions overlap (e.g., December-February).

Dx = interconnected to distribution; Tx = interconnected to transmission

Source: DEC and DEP. *Johnson DEP Exhibit 2 (Docket Nos. 2021-89-E and 2021-90-E)*. May 17, 2021. P. 8.

4 Review of DEC and DEP's proposed avoided cost methodology

4.1 Overview and framework for analysis

As discussed previously, DEC and DEP use the "peaker methodology" to arrive at the avoided cost rates paid to QFs, which consist of avoided cost rates for capacity and energy. As described by Mr. Snider, "*the peaker methodology is designed to determine a utility's marginal capacity and marginal energy cost, and therefore, can be applied to quantify a utility's avoided costs for purposes of pricing power purchases from QFs*" under the Companies' Schedule PP and Large QF tariffs.[50] Proxies for avoided capacity cost rates can be arrived at based on the fixed costs associated with a generic new peaking unit (simple-cycle combustion turbine or "CT"), while proxies for avoided energy cost rates can be arrived at based on variable avoided energy costs estimated through production cost simulation modeling. Combined, these two components are meant to represent the "*avoided or incremental costs of alternative capacity and energy that would have otherwise been incurred but for the purchase from a QF facility*."[51]

With the parties already in settlement, LEI's approach in conducting this review of the Companies' avoided cost methodology was primarily to determine whether the methodology as proposed results in plausible outcomes. Notably, LEI has focused its quantitative analysis on the resulting rates arrived at in the proposed settlement for avoided energy and capacity. Because modeling is subject to significant uncertainty, and is the product of the assumptions used, LEI has not sought to replicate the proposed numbers exactly or critique individual assumptions. Instead, LEI has performed independent modeling to demonstrate that the proposed rates fall within a reasonable range using a set of credible assumptions similar to those used in the Companies' filings and IRPs. Given that the proposed numbers are relatively close between DEC and DEP, their geographic proximity, and that the settlement encompasses both entities, LEI did not perform separate analysis for each Duke entity. Instead, LEI developed a "zone of reasonableness" for avoided costs in the Duke regions, and determined whether the proposed rates for each entity fell within it. This "zone of reasonableness" is discussed in the textbox on the following page.

For avoided capacity costs, which are discussed in Section 4.2, LEI first reviewed the methodology and assumptions used by the Companies, and then developed its own estimates of the current cost of entry for a peaking facility using publicly available data; where the Companies referenced a publicly available source themselves, LEI used that or a similar source. LEI found the publicly available sources cited by the Companies to be credible and similar to the sources LEI would have used itself. LEI's goal was not to develop an exact replica of the recommended numbers, but rather to determine whether such numbers were within an acceptable margin of difference from LEI's calculations. As actual peaker entry costs are highly site specific and reflect market conditions at the time materials and equipment are purchased, no individual project is going to match exactly the numbers proposed by the Companies or those calculated by LEI.

[50] DEC and DEP. *Direct Testimony of Glen A. Snider on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (Docket Nos. 2021-89-E and 2021-90-E)*. May 17, 2021. P. 14.

[51] Ibid. P. 15.

However, results presented by the Companies fall within a zone of reasonableness developed from LEI's analysis.

For avoided energy costs, which are discussed in Section 4.3, LEI first reviewed the methodology and assumptions used by the Companies where available, and then developed its own estimates for avoided energy costs. To conduct its own analysis and arrive at estimates for these avoided energy costs, LEI deployed its proprietary electricity market dispatch model, known as POOLMod. LEI used a 10-year forecast horizon, announced generation entry and exit dates, current fuel forecasts, prevailing regulations, and dynamic constraints consistent with modeled resources to develop a base case; then, a proportionate amount of no-cost generation was added in each year to determine the avoided energy costs. As with avoided capacity cost estimates, the outcomes from production cost modeling are driven by assumptions, which may differ from those used by the Companies. Nevertheless, the results from LEI's analysis of the avoided energy costs also fall within a zone of reasonableness as compared to results presented by the Companies.

Price forecasting error analysis and establishing a zone of reasonableness

The US Energy Information Administration ("EIA") releases annual estimates of various energy market indicators through its Annual Energy Outlook ("AEO") publication, such as projections for fuel prices (e.g., natural gas, coal), average retail electricity prices, and energy consumption. Once every two years, the EIA also issues its AEO Retrospective Review, which compares projections from previous editions of the AEO to actuals, thus "*[informing] discussions about the underlying models*" and "*[illustrating] the uncertainty inherent in long-term projections*."

The EIA's data on price forecasting error ("PFE") from the AEO Retrospective Review provides useful insights into the variations that can be expected between projections and actual outcomes, which are driven in large part by underlying modeling assumptions. In LEI's opinion, this can be informative in thinking about what may constitute an appropriate zone of reasonableness.

LEI sampled data from 27 editions of the AEO, comparing forecasts for retail electricity prices against actuals from issues dating back as far as 1994 and as recent as 2020. LEI calculated the PFE (taken as the absolute percentage difference between projected and actual values) and averaged the error depending on the forecast horizon. As demonstrated in the table below, the PFE tends to increase the farther out the forecast extends – for example, projections looking one year out tend to demonstrate a margin of error of 4% on average, while ten-year projections demonstrate a higher margin of error of 14% on average. These PFEs serve as the basis for LEI's determination of a zone of reasonableness of +/- ~10% around LEI calculations.

Number of years forward	1	2	3	4	5	6	7	8	9	10	Average
PFE (%) in absolute terms	4%	7%	8%	10%	11%	12%	13%	14%	14%	14%	11%

Source: EIA. *AEO Retrospective Review – Table 15b: Average electricity prices (nominal $)*. December 29, 2020.

4.2 Review of avoided capacity costs and resulting rates

LEI's understanding of the methodology used by DEC and DEP to establish the avoided capacity cost rates, as described in Mr. Snider's direct testimony and associated exhibits filed with the Commission on May 17th, 2021, is covered in the subsections below and summarized in Figure 11. The subsections are broken down into the methodology for calculating the annual capacity costs (in dollar terms), the methodology for calculating the avoided capacity costs (in dollar terms), and the methodology for calculating avoided capacity cost rates (volumetrically in cents/kWh, with seasonal allocations). Following this, results from LEI's analysis on potential capacity costs are summarized in Section 4.2.2.

Figure 11. Summary of process for establishing avoided capacity cost rates

Process (1)	Process (2)	Process (3)	Process (4)
Establish aggregate costs associated with construction of new CT unit, along with annual costs for FOM	Based on (1) and further adjustments, calculate **annual capacity costs** associated with new CT unit	Calculate **annual nominal avoided capacity costs** based on (2) and capacity needs, followed by **Present Values ("PV") of avoided capacity costs** over relevant periods	Convert the PV of avoided capacity costs into **annual annuitized avoided capacity costs**, then allocate these costs seasonally and volumetrically to establish avoided capacity cost rates

4.2.1 Methodology used by the Companies

4.2.1.1 Methodology to calculate annual capacity costs

As described in Mr. Snider's direct testimony and associated exhibits from May 17th, 2021, the methodology for calculating avoided capacity costs relies first on two cost estimates for a new CT unit: (i) the **capital costs** associated with constructing the peaker (referred to as "CT Cost" or "capital costs" below), and (ii) the **fixed operating and maintenance ("FOM") costs** associated with operating and maintaining the newly constructed CT unit (referred to as "FOM costs").

According to Mr. Snider, capital costs for the new peaker are based on information from the EIA's 2021 AEO, which provides the EIA's assessment of costs to develop and install various generating technologies, including the combustion turbine (industrial frame, 237 MW) unit being used in this analysis. LEI did not find evidence from the Companies on the starting value or source for FOM cost assumptions. The starting assumptions for both components have been redacted in Mr. Snider's exhibits, as they were designated as confidential and filed under seal.

For capital costs, the calculation begins with the aggregate CT Cost values from the EIA's 2021 AEO, which is first decreased to account for economies of scale, as according to Mr. Snider "*the Companies' practice is to build multiple units at a new site*."[52] Next, the aggregate cost value for the CT plant is levelized to arrive at an annualized value for the CT carrying cost, using "*levelized*

[52] Ibid. P. 19.

carrying charge rates applicable to new combustion turbine installed cost."[53] These annual carrying cost dollar values are then adjusted upwards based on a General Plant Factor, which is derived using the 5-year historical average (2015-2019) of production demand. Following this, the value is adjusted upwards again by a Performance Adjustment Factor ("PAF") to account for resource unavailability – this PAF is based on the "*reliability equivalence of the Companies' respective generation fleets*."[54] One final adjustment is made to arrive at a separate Annual Capacity Cost for transmission- and distribution-connected capacity; this is done by applying a Marginal Loss Factor, which results in slightly higher capacity costs for distribution-connected capacity, to recognize the avoidance of transmission system line losses at the distribution level. Through these adjustments, the starting capital cost assumptions for a new CT are converted into annualized capital costs for new capacity at the distribution and transmission levels and take into account "*recovery-of and return-on the investment*."[55]

For FOM costs, as mentioned previously LEI did not find evidence from the Companies on the starting value for FOM. Nevertheless, the starting value for FOM is adjusted by a Working Capital Factor, which is derived from the 5-year historical average (2015-2019) of working capital as a percentage of non-fuel production O&M. In line with the approach for capital costs, this annual FOM value is then adjusted upwards by the PAF, and finally by the Marginal Loss Factor to arrive at annual FOM costs at the distribution and transmission level.

For both capital costs and FOM, the adjustments being applied differ slightly between DEC and DEP, leading to slightly higher annualized capital costs and slightly lower FOM costs for DEC as compared to DEP. This approach to arriving at the annual capacity cost is summarized in Figure 12. As the dollar values were redacted in the Companies' filings, LEI has had to back into its own estimates, which are shown in red. LEI calculated these estimates for the redacted values using both the framework outlined in the Companies' filings and the resulting avoided capacity cost present values ("PV").

[53] DEC and DEP. *Snider DEC Exhibit 1, Snider DEP Exhibit 1 (Docket Nos. 2021-89-E and 2021-90-E).* May 17, 2021. P. 8.

[54] DEC and DEP. *Direct Testimony of Glen A. Snider on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (Docket Nos. 2021-89-E and 2021-90-E).* May 17, 2021. P. 19.

[55] Ibid. P. 17.

Figure 12. Process for determining annual capital and FOM costs (2021 $000's)

Item	Formula	DEC				DEP			
		Distribution		Transmission		Distribution		Transmission	
		CT Cost	FOM	CT Cost	FOM	CT Cost	FOM	CT Cost	FOM
[A] Installed Combustion Turbine Cost		$ 163,727		$ 163,727		$ 163,205		$ 163,205	
[B] Combustion Turbine Fixed Charge Rate		10.204%		10.204%		9.88%		9.88%	
[C] Annual Combustion Turbine Carrying Cost	[A]*[B]	$ 16,707		$ 16,707		$ 16,125		$ 16,125	
[D] General Plant Factor		1.0362		1.0362		1.0211		1.0211	
[E] Adjusted Annual Combustion Turbine Carrying Cost	[C]*[D]	$ 17,312		$ 17,312		$ 16,465		$ 16,465	
[F] Combustion Turbine Fixed O&M Expenses			$ 846		$ 846		$ 846		$ 846
[G] Working Capital Factor			1.0353		1.0353		1.0498		1.0498
[H] Subtotal	[E]+[F]*[G]	$ 17,312	$ 876	$ 17,312	$ 876	$ 16,465	$ 888	$ 16,465	$ 888
[I] Performance Adjustment Factor		1.07	1.07	1.07	1.07	1.08	1.08	1.08	1.08
[J] Marginal Loss Factor		1.0289	1.0289	1.0011	1.0011	1.0215	1.0215	1.0010	1.0010
[K] Annual Capacity Cost	[H]*[I]*[J]	$ 19,059	$ 964	$ 18,544	$ 938	$ 18,165	$ 980	$ 17,799	$ 960

Notes: Dollar values shown in red text are LEI estimates. Actual values from Companies' filings were designated as confidential and filed under seal. Adjustment factors shown in blue text are taken directly from Companies' filings.

Source: LEI analysis; DEC and DEP. *Snider DEC Exhibit 1, Snider DEP Exhibit 1 (Docket Nos. 2021-89-E and 2021-90-E).* May 17, 2021.

4.2.1.2 Methodology to calculate avoided capacity costs

The approach described above provides annual capital and FOM costs, which are the two components of annual capacity costs. To arrive at the annual nominal avoided capacity costs, the methodology makes additional adjustments accounting for (i) inflation rates (as annual costs are initially calculated in 2021 dollar terms), and (ii) perceived capacity needs. For inflation rates, the annual capital and FOM costs are escalated starting in 2022 at rates of 0.86% and 2.5%, respectively. Perceived capacity needs are based on the IRPs for DEC and DEP, which show the first avoidable capacity needs emerging in 2026 and 2024, respectively.[56] Starting in these years, the avoided capacity cost is based on the annual capital and FOM costs described previously; for years prior to this perceived capacity need emergence, the avoided capacity cost is $0 – otherwise, according to Mr. Snider, "*customers would be paying a QF for marginal capacity that is providing no actual benefit to serve their needs for capacity*."[57]

This approach is summarized in Figure 13, which uses the annual capital and FOM costs from Figure 12, the first year that an avoidable capacity need emerges based on Company IRPs, and the capital and FOM escalation rates to determine the annual nominal avoided capacity costs (which is the sum of annual capital/CT Costs and FOM costs).

Once the annual nominal avoided capacity costs have been established, the next step is to calculate the avoided capacity costs used to determine the 10-year fixed long-term rate, the 5-year fixed long-term rate, and the variable rate. This is done by simply taking the PV of annual nominal

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[56] Since the IRPs are the subject of a separate proceeding, LEI is not inclined to opine on the first year of capacity needs for either Company.

[57] DEC and DEP. *Direct Testimony of Glen A. Snider on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (Docket Nos. 2021-89-E and 2021-90-E).* May 17, 2021. P. 20.

avoided capacity costs (i.e., the combination of capital and FOM costs) using a discount rate of 6.56% and 6.37% for DEC and DEP, respectively. PVs are determined for the annual avoided costs over the 2022-2031 timeframe for the 10-year fixed long-term rate, the 2022-2026 timeframe for the 5-year rate, and the 2022-2023 timeframe for the variable rate. This approach is summarized in Figure 14, which shows the PV of the avoided CT and FOM costs over the relevant timeframes, along with the PV of avoided capacity costs (sum of CT Cost and FOM PVs). Using this approach, the PVs for DEP are higher than for DEC, owing to its earlier emergence of avoidable capacity needs (and therefore more streams of annual capacity costs). The values shown in Figure 14 were included in Mr. Snider's exhibits and were used by LEI as the basis when backing into estimates for the redacted values shown previously.

Figure 13. Process to determine annual nominal avoided capacity costs (nominal $000's)

Year	DEC (First year need emerges: 2026)				DEP (First year need emerges: 2024)			
	Distribution		Transmission		Distribution		Transmission	
	CT Cost	FOM	CT Cost	FOM	CT Cost	FOM	CT Cost	FOM
2022	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2023	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2024	$ -	$ -	$ -	$ -	$ 18,639	$ 1,055	$ 18,263	$ 1,034
2025	$ -	$ -	$ -	$ -	$ 18,799	$ 1,081	$ 18,420	$ 1,059
2026	$ 19,893	$ 1,091	$ 19,355	$ 1,062	$ 18,961	$ 1,108	$ 18,579	$ 1,086
2027	$ 20,064	$ 1,118	$ 19,522	$ 1,088	$ 19,124	$ 1,136	$ 18,739	$ 1,113
2028	$ 20,237	$ 1,146	$ 19,690	$ 1,115	$ 19,288	$ 1,164	$ 18,900	$ 1,141
2029	$ 20,411	$ 1,175	$ 19,859	$ 1,143	$ 19,454	$ 1,193	$ 19,062	$ 1,169
2030	$ 20,586	$ 1,204	$ 20,030	$ 1,172	$ 19,621	$ 1,223	$ 19,226	$ 1,199
2031	$ 20,763	$ 1,235	$ 20,202	$ 1,201	$ 19,790	$ 1,254	$ 19,392	$ 1,229

Notes: Dollar values shown in red text are LEI estimates. Actual values from Companies' filings were designated as confidential and filed under seal.

Source: LEI analysis; DEC and DEP. *Snider DEC Exhibit 1, Snider DEP Exhibit 1 (Docket Nos. 2021-89-E and 2021-90-E).* May 17, 2021.

Figure 14. Actual avoided capacity cost PVs from Duke filings ($000's)

Avoided Capacity Cost PV over timeframe:	DEC					
	Distribution			Transmission		
	CT Cost	FOM	Capacity costs	CT Cost	FOM	Capacity costs
2-year PV (2022-2023)	$0	$0	$0	$0	$0	$0
5-year PV (2022-2026)	$14,478	$794	$15,272	$14,087	$773	$14,859
10-year PV (2022-2031)	$76,052	$4,333	$80,385	$73,995	$4,216	$78,211

Avoided Capacity Cost PV over timeframe:	DEP					
	Distribution			Transmission		
	CT Cost	FOM	Capacity costs	CT Cost	FOM	Capacity costs
2-year PV (2022-2023)	$0	$0	$0	$0	$0	$0
5-year PV (2022-2026)	$44,095	$2,535	$46,630	$43,208	$2,484	$45,691
10-year PV (2022-2031)	$103,613	$6,181	$109,793	$101,527	$6,056	$107,583

Source: DEC and DEP. *Snider DEC Exhibit 1, Snider DEP Exhibit 1 (Docket Nos. 2021-89-E and 2021-90-E).* May 17, 2021.

4.2.1.3 Methodology to calculate avoided capacity cost rates

The PVs of avoided capacity costs shown previously in Figure 14 are used as the basis for determining the 10-year fixed long-term rate, the 5-year fixed long-term rate, and the variable rate. First, monthly annuity payments are calculated on these PVs based on their respective timeframes and discount rates. For example, the monthly avoided capacity cost for DEP's 5-year fixed long-term rate is calculated assuming an annuity over 60 months with an ordinary monthly annuity factor at a rate of 0.5160% (based on an annual discount rate of 6.37%); the monthly avoided capacity cost for DEC's 10-year fixed long-term rate is calculated assuming an annuity over 120 months with an ordinary monthly annuity factor at a rate of 0.5308% (based on an annual discount rate of 6.56%). This value is then annualized, by multiplying the resulting monthly annuities by 12, to get to the annual annuitized avoided capacity costs.

The annual annuitized avoided capacity costs are then allocated between the summer (July and August) and winter seasons (December to March), based on when new capacity resource additions are needed most for system reliability. As proposed in the Companies' joint application, the seasonal allocation was initially based on the 2018 Value of Solar Capacity Study, which determined an allocation of 89% winter/11% summer and 100% winter/0% summer for DEC and DEP respectively, based on the total loss of load risk occurring in each season. However, ORS witness Brian Horii recommended that findings from the 2020 Resource Adequacy Study should be incorporated instead, with some modifications as discussed in Section 3.1.3, which ultimately shifted DEC's seasonal allocation to 95% winter/5% summer. LEI generally agrees with this adjustment, as it leverages the updated modeling assumptions used in the 2020 Study while appropriately scaling the resulting seasonal allocations based on the current level of solar capacity on DEC and DEP's systems (including capacity from solar facilities with executed PPAs). More generally, LEI also agrees with the approach of allocating capacity payments according to system peaking needs.

Applying these allocations to the capacity costs provides the seasonal allocation of the annual capacity costs. Up to this point, all values have been in dollar terms. Thus, one final process is required to arrive at volumetric (cents/kWh) rates. First, the seasonal capacity allocations are converted into $/kW terms, by dividing the dollar values by 237,000 kW (which is the size of the generic CT unit from the EIA's 2021 AEO). Finally, these seasonal capacity credits in $/kW terms are converted into cents/kWh terms; this is done through dividing by the number of peak hours in each season (248 hours and 605 hours for summer and winter, respectively). With this final step, the seasonal capacity credits (or avoided capacity cost rates) shown previously in Figure 8 (for DEC) and Figure 4 (for DEP) are established.

A summary of this methodology is shown in Figure 15 for reference, using DEC's 10-year fixed long-term rate for transmission, and DEP's 5-year fixed long-term rate for distribution as examples. The methodology for establishing the remaining capacity rates not shown in Figure 15 is the same, with the only difference being the avoided capacity costs; given that the avoided capacity costs for variable rates are $0 for both DEC and DEP, the resulting variable capacity rates are also $0.

Figure 15. Methodology for calculating avoided capacity cost rates

Item	Formula	DEC: 10-Year Fixed Long-Term Rate, Transmission		DEP: 5-Year Fixed Long-Term Rate, Distribution	
[A] Avoided Capacity Cost ($000's) *PV of 2022-2031 for 10-year* *PV of 2022-2026 for 5-year*		$78,211		$46,630	
[B] Monthly Avoided Capacity Cost ($000's)	PMT([E],[C],[A])	$883		$906	
[C] Period (months)	# years * 12 months	120		60	
[D] Annual discount rate		6.56%		6.37%	
[E] Monthly discount rate	(1+[D])^(1/12 months) - 1	0.5308%		0.516%	
[F] Annual Avoided Capacity Cost ($000's)	[B]*12	$10,594		$10,868	
		Summer	**Winter**	**Summer**	**Winter**
[G] Seasonal Allocation (%)		5%	95%	0%	100%
[H] Seasonal Allocation of annual capacity cost ($000's)	[F]*[G]	$530	$10,064		$10,868
[I] Peaker capacity rating (MW)		237	237		237
[J] Seasonal Capacity Credit ($/kW)	[H]/[I]	$2.23	$42.46		$45.86
[K] Seasonal Peak Hours		248	605		605
[L] Seasonal Capacity Credits (¢/kWh)	([J]/[K])*100	**$0.90**	**$7.02**		**$7.58**

Source: Source: DEC and DEP. *Snider DEC Exhibit 1, Snider DEP Exhibit 1 (Docket Nos. 2021-89-E and 2021-90-E).* May 17, 2021.

4.2.2 Methodology used by LEI to estimate potential capacity costs

As part of its review process, LEI conducted a similar bottom-up estimate of the capacity costs associated with a new peaker. This analysis is functionally similar to the process undertaken by the Companies to arrive at all-in fixed costs for a generic new CT unit (specifically, line item [H] of Figure 12). For cost assumptions, LEI also assumed a 237 MW frame peaker, and relied solely on data from the EIA's 2021 AEO for both the total capital costs and FOM values, without any adjustments for economies of scale, general plant factors, or working capital factors. The weighted average cost of capital ("WACC") was assumed to equivalate to the discount rates used by the Companies, at 6.56% and 6.37% for DEC and DEP respectively, which results in slightly different capacity cost outcomes, and the payback period was assumed to be 17 years.[58] Combined, these WACC and payback period assumptions function similarly to the fixed charge rate assumption used by the Companies (specifically, line item [B] of Figure 12).

All-in fixed costs based on this analysis are shown at the bottom of Figure 16. Although the approach and assumptions LEI used result in lower capital costs and higher FOM costs,[59] the

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[58] The timeframe over which a peaking plant can recover its costs depends on prevailing regulations; anticipation of future restrictions on natural gas use might suggest the need for a shorter recovery period, but no such regulations currently exist in South Carolina. A 17-year amortization period was assumed to account for risks associated with project life.

[59] The starting numbers used by the Companies do not appear to have been highlighted in the public testimony. However, the differences for capital costs may be due to LEI's use of EIA data specific to the larger SERC Reliability Corporation/East ("SRCA") subregion, while FOM differences may be due to LEI's use of EIA data for FOM costs.

resulting all-in fixed cost estimates for capacity are very similar to those estimated by the Companies (line item [H] of Figure 12), being around 3% lower and 0.2% higher for DEC and DEP, respectively.

Figure 16. Relevant assumptions used by LEI to estimate all-in fixed capacity costs (2021 $000's)

Item	Unit	DEC	DEP
Peaker capital cost ($'000s)	($'000s)	$ 154,338	$ 154,338
Weighted average cost of capital	%	6.56%	6.37%
Capitalization recovery period	years	17	17
Fixed O&M	($'000s)	$1,668	$1,668
All-in fixed cost (annual)	**($'000s)**	**$17,636**	**$17,385**

Source: LEI analysis, with some assumptions from the EIA's 2021 AEO and Snider's DEC and DEP Exhibits 1.

LEI then subjected this all-in fixed cost estimate to the further adjustments described in Section 4.2.1. In general, LEI finds the Companies' combined assumptions around the PAF and Marginal Loss Factor to be reasonable, as well as the combined assumptions for the escalation rates applied to capital and FOM costs. Once these adjustments are made, the values presented by the Companies for avoided capacity cost rates are within 5% of those independently calculated by LEI, which LEI views as an acceptable zone of reasonableness. For reference, presented in Figure 17 are the spreads for avoided capacity cost rates, with the spread representing the percentage difference between the resulting avoided capacity cost rates using LEI's all-in fixed cost assumptions, versus the avoided capacity cost rates proposed by the Companies.

Figure 17. Spread between avoided capacity cost rates using different input cost assumptions

Item	DEC				DEP			
	Distribution		Transmission		Distribution		Transmission	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Variable Rate	0.0%	0.0%	0.0%	0.0%		0.0%		0.0%
5 Year Fixed Long-Term Rate	-1.3%	-2.7%	-4.0%	-2.5%		0.5%		0.4%
10 Year Fixed Long-Term Rate	-2.9%	-2.4%	-2.3%	-2.5%		0.7%		0.7%

Note: Spreads may vary in this comparison due to rounding.

Source: LEI analysis.

LEI's opinion of the Companies' approach to calculating avoided capacity costs

Based on a review of the Companies' approach to calculating avoided capacity costs, LEI is comfortable with the methodology and the resulting cost assumptions. LEI conducted its own bottom-up estimation of the annual fixed costs associated with a hypothetical new capacity resource. For the referent capacity resource, LEI agrees that a CT frame peaker serves as an appropriate referent for generic capacity, and is often used as the reference technology in organized wholesale markets when setting parameters for capacity mechanisms. LEI further agrees with the use of the EIA's 2021 AEO, as this source was also used by LEI in conducting its own bottom-up estimation of annual fixed costs for new capacity. Certain aspects of the adjustments used by the Companies, such as for economies of scale, were not fully discussed in the Companies' submissions, and thus LEI cannot speak to their appropriateness. However, results from LEI's own bottom-up analysis come within 5% of the values presented by the Companies, which LEI views as within a zone of reasonableness.

LEI also believes basing the year of first capacity needs on information from the Companies' IRPs is appropriate, and that the seasonal allocation of capacity costs based on expected system needs is adequately documented.

4.3 Review of avoided energy costs and resulting rates

As described by Mr. Snider, avoided energy costs "*represent an estimate of the system's marginal variable operating costs that are avoided and would have otherwise been incurred by the utility but for the purchase from a QF.*"[60] These variable costs include avoided fuel costs, avoided environmental costs (sulfur dioxide and nitrogen oxide, but not "speculative" carbon dioxide emissions costs), and avoided non-fuel variable O&M costs ("VOM").

Production cost simulation modeling is deployed to estimate these avoided energy costs. At a very high level, production cost modeling can be described as a simulation of energy prices ($/MWh) on an hourly basis, based on generating resource commitment under modeled supply and demand conditions; hourly energy prices (variable production costs) are set by the "marginal" clearing unit, or the highest-priced generating resource that is dispatched. This production cost modeling is performed for two "simulations" over a 10-year forecast horizon (2022-2031). The first simulation is used to establish a "base case" and uses "*IRP models and current market assumptions*"; the second simulation "*is identical to the first but adds a hypothetical 100 MW of no-cost generation to the utility's generating fleet, which is available to the system in every hour of the ten-year period*."[61] The addition of the 100 MW no-cost generation in the second simulation displaces supply from the marginal clearing unit in the first (base case) simulation, which would typically lower the market-clearing price. Thus, comparing the resulting savings from the second simulation as compared to the first simulation, and converting this value to $/MWh terms (by dividing the savings by the output of the 100 MW unit assuming 100% load factor) provides

[60] DEC and DEP. *Direct Testimony of Glen A. Snider on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (Docket Nos. 2021-89-E and 2021-90-E)*. May 17, 2021. P. 14.

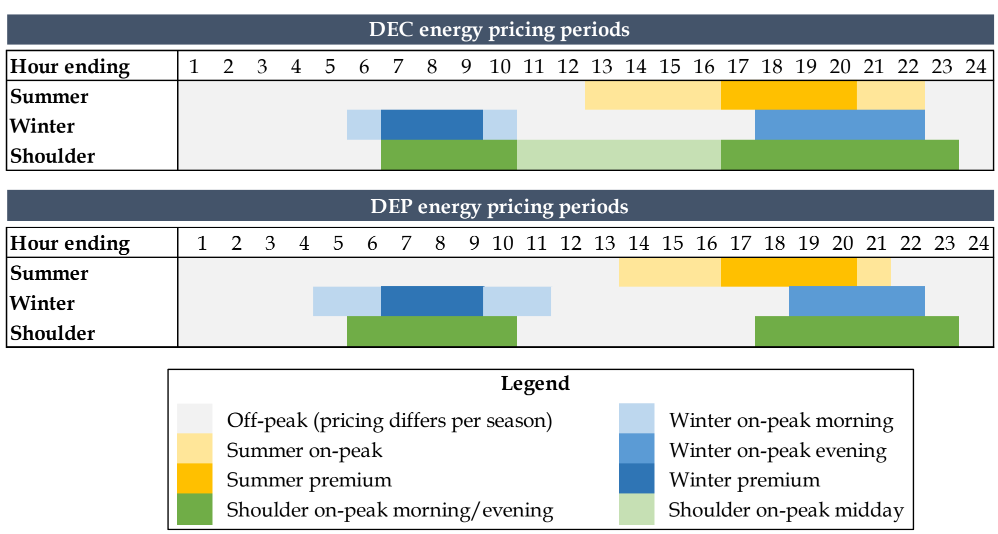
[61] Ibid. P. 25.

nominal avoided energy cost estimates over the 10-year timeframe. These values are then levelized by time period to arrive at avoided energy rates (cents/kWh). The modeling and analysis of the avoided energy rates is done for DEC and DEP individually, to calculate avoided energy rates "*that leave a customer indifferent between QF purchases and generation provided by the utility*."[62]

The approach to levelization is similar to that used for avoided capacity costs. The PV of the nominal avoided energy costs are estimated using discount rates of 6.56% and 6.37% for DEC and DEP, respectively, and are determined over the 2022-2031 timeframe for the 10-year fixed long-term rate, the 2022-2026 timeframe for the 5-year rate, and the 2022-2023 timeframe for the variable rate. These PVs are then annuitized, using the same discount rates and a period equal to the timeframe of the rates (i.e., 10 years, 5 years, 2 years).

For time period allocation, the avoided energy rates for DEC and DEP are differentiated on a seasonal and time-of-use basis. Seasons are divided into summer (June-September), winter (December-February), and shoulder (March-May and October-November) months. Hourly pricing periods are then developed to establish on-peak, off-peak, and premium periods – where the higher priced premium periods apply to only the summer and winter months and are designed "*to incent generation during these hours when the value of the energy avoided by QF power is greatest for customers*."[63] The hourly pricing periods differ slightly between DEC and DEP, reflecting "*differences in each utility's load profile net of solar generation*,"[64] and are depicted in Figure 18 below. In total, there are ten pricing periods for DEC and nine pricing periods for DEP.

Figure 18. Energy pricing time periods for DEC and DEP



Source: DEC and DEP. *Snider DEC/DEP Exhibit 3 (Docket Nos. 2021-89-E and 2021-90-E).* May 17, 2021.

[62] Ibid.

[63] Ibid. P. 28.

[64] Ibid.

After establishing the avoided energy costs by time period, three other adjustments are made to arrive at the energy credits (or avoided energy cost rates). First, the avoided energy costs are adjusted upwards by a Working Capital Factor, which is derived from the 5-year historical average (2015-2019) of working capital as a percentage of burned fuel. Next, this value is adjusted upwards by a Marginal Loss Factor; as with capacity rates, this adjustment results in higher costs for distribution-connected energy, to recognize slightly lower line losses at the distribution level as compared to the transmission system. The Marginal Loss Factor for transmission- and distribution-connected generation also accounts for avoided losses from generation step-up voltages, and the total Marginal Loss Factor varies depending on the time periods, generally being higher during peak seasons and hours. Finally, a generating excise tax of 0.05 cents is added, and factoring in these three adjustments provides the energy credits for the different rates and time periods. For reference, two examples of this process are shown in Figure 15 below for DEC and DEP; the full list of avoided energy cost rates were shown previously in Figure 2 (for DEC) and Figure 3 (for DEP).

Figure 19. Methodology for calculating avoided energy cost rates (cents/kWh)

Item		DEC: Variable Rate, Distribution, Summer off-peak	DEP: 10-Year Fixed Rates, Transmission, Shoulder Peak	Does line item vary by: Time period (seasonally & hourly)	Rate type (variable, 5-year, 10-year)	Connection type (distribution/ transmission)	Company (DEC/ DEP)
[A]	Avoided Energy Cost (¢/kWh)	2.04	2.90	Yes	Yes	No	Yes
[B]	Working Capital Factor	1.0152	1.0144	No	No	No	Yes
[C]	Marginal Loss Factor	1.0205	1.0007	Yes	No	Yes	Yes
[D]	SC Generating Excise Tax (¢)	0.05	0.05	No	No	No	No
[A]*[B]*[C]+[D]	**Energy Credits (¢/kWh)**	**2.16**	**3.00**	Yes	Yes	Yes	Yes

Source: DEC and DEP. *Snider DEC Exhibit 1, Snider DEP Exhibit 1 (Docket Nos. 2021-89-E and 2021-90-E)*. May 17, 2021.

As part of this review process, LEI also conducted its own forecast of avoided energy costs, using its proprietary simulation model POOLMod, which is presented in Appendix A (Section 7). Consistent with the production cost modeling conducted by the Companies, LEI forecasted a 10-year forward period (2022-2031) under two scenarios, a "base case" and an "alternative case" which simply adds hypothetical no-cost generation to the base case. LEI's base case is based on outlooks for demand and supply conditions (notably announced generation entry and exit dates), fuel costs, prevailing regulations, and a set of dynamic constraints. While the record appeared to provide limited public information regarding the assumptions used by the Companies to perform their modeling, it would be surprising if the assumptions differed greatly from the Companies' IRPs. For this reason, LEI instead compared some of its key assumptions against the base case assumptions used in the Companies' 2020 IRPs. A summary of these key assumptions is provided in Figure 20 below.

One notable difference in LEI's approach is that, because LEI's market topology for the region that encompasses DEC and DEP service territories includes other entities, the size of the hypothetical unit in the "alternative case" was increased proportionally to account for (i) modeling both DEC and DEP together, and (ii) modelling additional entities. Because of this, LEI compared its resulting avoided energy cost estimates against the weighted average of the results from DEC and DEP's avoided energy cost estimates. Based on this comparison, LEI's results were within 1.8%, 2.9%, and 4.1% of the weighted average avoided energy costs presented by the Companies (for the 2-year, 5-year, and 10-year timeframes, respectively), which is within the zone of reasonableness discussed at the start of this section.

Figure 20. Summary of key assumptions used by LEI (2021), DEC (2020 IRP), and DEP (2020 IRP)

Assumption	DEC	DEP	LEI
Gas prices	Henry Hub gas prices commencing ~$2.5/MMBtu in 2022, remain relatively flat to 2030, increase to ~$3/MMBtu in 2031. Outlook for Transco Zone 5 appears to not be included in IRP	Same as DEC	Transco Zone 5 gas prices commencing ~$3/MMBtu in 2022, increasing to ~$4.5/MMBtu in 2031, growing at a compound annual growth rate ("CAGR") of 4.5%
Load growth	Peak demand grows at a CAGR of 0.9% over 2022-2031 timeframe, energy consumption grows at CAGR of 0.7%	Peak demand grows at a CAGR of 0.8% over 2022-2031 timeframe, energy consumption grows at CAGR of 1.1%	Peak demand grows at a CAGR of 0.5% over 2022-2031 timeframe, energy consumption grows at CAGR of 0.4%
Supply	Winter capacity of ~23.2 GW. Additions of ~4.6 GW between 2022 and 2031, mostly solar, storage, and CT. Retirements of ~3.4 GW, mostly coal	Winter capacity of ~13.7 GW. Additions of ~7.4 GW between 2022 and 2031, mostly CT, solar, storage, and CC. Retirements of ~1.8 GW, mostly coal	Nameplate capacity of ~53 GW (includes but not limited to both DEC and DEP). Additions of ~16.3 GW between 2022 and 2031, mostly mostly CT, solar, and storage. Retirements of ~10.3 GW, mostly coal

Note: Gas price assumptions are from pages 158 of DEC and DEP's IRPs, for 'base blended fuel' line in graph; load growth assumptions are from pages 242 and 233 of DEC and DEP's IRPs, respectively; supply assumptions are from pages 109 and 107 of DEC and DEP's IRPs, for the 'base case without carbon policy.'

Sources: LEI analysis, DEC 2020 IRP, DEP 2020 IRP.

LEI's opinion of the Companies' approach to calculating avoided energy cost rates

Based on a review of the Companies' approach to calculating avoided energy costs and rates, LEI believes the methodology and the resulting avoided energy cost rates are reasonable. In general, LEI agrees with the use of production cost modeling, and allocation of avoided costs based on value according to expected periods of peak hours and seasons. Without reviewing assumptions used in the production cost modeling, LEI is unable to comment on their plausibility. However, the weighted-average values presented by the Companies are within 5% of LEI's own production cost modeling, resulting in avoided energy costs that LEI views as falling within a zone of reasonableness.

5 Evaluation of the terms and conditions in DEC and DEP's proposed standard offer, form contract, and commitment to sell form

5.1 Overview and framework for analysis

As dictated by Act No. 62, and discussed previously in Section 2.2, the Commission is required to ensure the nondiscriminatory treatment of small power producers. This includes, among other directives, ensuring that "*power purchase agreements, including terms and conditions, are commercially reasonable and consistent with regulations and orders promulgated by the Federal Energy Regulatory Commission implementing PURPA*."[65]

Although the term "commercially reasonable" is not explicitly defined in Section 58-41-20 of the South Carolina Code, LEI generally takes this to mean that the agreements, and terms and conditions proposed by DEC and DEP should be "*fair, done in good faith, and correspond to commonly accepted commercial practices*."[66] This understanding aligns with several publicly available PPAs that LEI reviewed, which include the following definition:

> *"Commercially Reasonable" or "Commercially Reasonable Efforts" means, with respect to any action required to be made, attempted or taken by a Party …, the level of effort in light of the facts known to such Party at the time a decision is made that: (a) can reasonably be expected to accomplish the desired action at a reasonable cost; (b) is consistent with Prudent Utility Practice; and (c) takes into consideration the amount of advance notice required to take such action, the duration and type of action and the competitive environment in which such action occurs.*[67]

Notably, DEC and DEP's Large QF PPA (form contract) itself includes a definition of commercially reasonable, which shares commonalities with the interpretations discussed above – including an expectation of **good faith efforts** by parties to the agreement, which should be in line with **standard industry practice**. Specifically, the Companies' Large QF PPA defines "Commercially Reasonable Manner" or "Commercially Reasonable" in part as:

> *with respect to a given goal or requirement, the manner, efforts and resources a reasonable person in the position of the promisor would use, in the exercise of its reasonable business discretion and industry practice, so as to achieve that goal or requirement, which in no event shall be less than the level of efforts and resources standard in the industry for comparable companies with respect to comparable products.*[68]

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[65] South Carolina Legislature. South Carolina Code, Title 58, Chapter 41: Renewable Energy Programs. May 16, 2019.

[66] Merriam-Webster. Commercially reasonable.

[67] *See for example* Xcel Energy. Wind Energy Purchase Agreement. February 2013 *or* Chugach Electric Association, Inc. Eklutna Power Purchase Agreement. December 2018.

[68] DEC and DEP. *Johnson Stipulation Exhibit 5 (Docket Nos. 2021-89-E and 2021-90-E).* July 23, 2021. P. 3.

LEI reviews DEC and DEP's proposed Standard Offer PPA and Terms and Conditions, Large QF PPA, and Notice of Commitment Form in turn in the following subsections, keeping the Commission's aforementioned directives in mind. LEI focuses the bulk of its evaluation on the Large QF PPA, as this contract contains the most modifications since the version approved by the SC PSC in the 2019 avoided cost proceeding.

5.2 Standard offer

As discussed in Section 3.1.4, eligible QFs with facilities up to 2 MW in size that wish to transact with the Companies under the Schedule PP (standard offer) rates are subject to the Standard Offer PPA (*Power Purchase Agreement by a Qualifying Cogenerator or Small Power Producer*) and the Standard Offer Terms and Conditions (*Terms and Conditions for the Purchase of Electric Power*).

Clean copies of these documents were submitted by Mr. Johnson on behalf of DEC and DEP in Johnson DEC Exhibits 3 and 4 and Johnson DEP Exhibits 3 and 4, respectively. As noted by the Companies in their joint application, "*[t]he only changes to the Standard Offer PPA and Standard Offer Terms and Conditions are the designations in the header and footer of the documents, and as such, the Companies are filing only clean versions of those documents*."[69]

As proposed, DEC and DEP's Standard Offer PPA is a brief 6-page agreement that is "*essential to establishing the physical parameters that support interconnecting the QF to the Companies' grid and to memorializing the commercial terms of purchasing the QF's power*."[70] As such, the PPA includes, but is not limited to, the following details:[71]

- **site location**;
- expected **generation capacity**, as well as details such as the facility's fuel type and whether or not it will be connected to a storage resource;
- estimated **annual energy production** (in kWh);
- expected **date of operation** – notably under Section 3 of the Standard Offer PPA, the Companies may terminate the agreement on July 2nd, 2022, if the eligible QF is not yet operational and delivering energy as specified, subject to certain extensions;
- **point of interconnection**;
- **technical service requirements**, such as whether the electricity supplied by the QF shall be single or three phase, and specifying the delivery voltage; and

[69] DEC and DEP. *Joint Application of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (Docket Nos. 2021-89-E and 2021-90-E)*. April 22, 2021. P. 16.

[70] DEC and DEP. *Direct Testimony of David B. Johnson on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (Docket Nos. 2021-89-E and 2021-90-E)*. May 17, 2021. P. 9.

[71] Ibid.

- the desired **contract term** (one-year energy only, or five- or ten-year energy and capacity) and applicable **Schedule PP rate option** (variable or fixed, distribution- or transmission-connected).

The Standard Offer PPA refers in several instances to the 11- to 12-page Standard Offer Terms and Conditions, which "*set forth the contractual obligations of both the QF and the Companies as necessary to administer Schedule PP and the Standard Offer PPA in a fair and consistent manner*."[72] As described in Mr. Johnson's direct testimony, the Terms and Conditions address the following topics, among others:

- **the impacts and remedies for failing to meet obligations:** for example, DEC and DEP have the right to terminate or suspend the agreement (upon written notice) if the QF has failed to deliver energy for six consecutive months – the QF has five calendar days after receiving written notice to cure the violation;
- **billing issues:** for example, meter readings will be taken monthly – in the event the meter cannot be read, production may be estimated based on the facility's production during the most recent preceding billing period for which readings were obtained, unless some unusual condition is known to exist; and
- **payment for interconnection facilities:** which, as discussed in Section 3.1.4, includes a monthly Interconnection Facilities Charge calculated "*based on 1.0 percent of the estimated original installed cost and rearrangement cost of all facilities, including metering, required to accept interconnection, but not less than $25 per month*" (unless the interconnection facilities consist only of the meter, in which case this $25 minimum is waived).[73]

LEI's opinion of DEC and DEP's proposed Standard Offer PPA and Terms and Conditions

As noted by Mr. Johnson in his direct testimony, referring to the Standard Offer PPA and Terms and Conditions: "*the Commission found these documents to be commercially reasonable in the 2019 Avoided Cost Proceeding*" (p. 12). Following a review of these documents as proposed by the Companies in the current proceeding, LEI believes they continue to be so.

Importantly, these documents are unchanged from the versions previously approved by the SC PSC, except for administrative updates to the designations in the headers and footers. Given these minimal changes, it is LEI's view that the Commission should continue to find the Standard Offer PPA and Terms and Conditions commercially reasonable and consistent with PURPA, and thus should approve the documents as proposed by DEC and DEP.

[72] Ibid. P. 11.

[73] DEC and DEP. *Johnson DEC Exhibit 4 (Docket Nos. 2021-89-E and 2021-90-E)*. May 17, 2021. P. 24.

5.3 Form contract

The Companies' Large QF PPA (form contract), is a 72-page document that applies to QFs with a facility above 2 MW and up to 80 MW in size – these projects are not eligible for the standard offer. As required under Section 58-41-20(A) of the South Carolina Code, form contract PPAs should "*contain provisions, including, but not limited to, provisions for force majeure, indemnification, choice of venue, and confidentiality provisions and other such terms, but shall not be determinative of price or length of the power purchase agreement*."[74]

Figure 21. Required provisions under Act No. 62 as covered in the Large QF PPA

Provision	Summary/location of the provisions in DEC/DEP's Large QF PPA

Force majeure	• Section 14 – Force Majeure
	• A Force Majeure event is defined as including the following (Section 14.1 – Definition):
	  o war, riots, floods, hurricanes, tornadoes, earthquakes, lightning, ice-storms, excessive winds, and other such extreme weather events and natural calamities;
	  o explosions or fires arising from lightning or other natural causes unrelated to acts or omissions of the Party;
	  o insurrection, rebellion, nationwide strikes;
	  o an act of god or other such significant and material event or circumstance which prevents one Party from performing material and significant obligations; and
	  o delays in obtaining goods or services from any subcontractor or supplier to the extent caused by the occurrence of any of the events described above.
	• Requires notification of a Force Majeure event as soon as reasonably practicable, but no later than three business days of the initial occurrence (see Section 14.2 – Event)
	• If a bona fide Force Majeure event persists for a continuous period of 180 days, then the Party not claiming Force Majeure shall have the right to terminate the Agreement with 10 business days' advance written notice, subject to a potential additional 180-day extension (see Section 14.4 – Remedy)

Indemnification	• Default Liquidated Damages are calculated as (see Section 1.24):
	  o for facilities up to 15 MW: equal to the average annual estimated capacity payments under the Agreement over the Term; and
	  o for facilities > 15 MW: the average annual estimated capacity payments under the Agreement over the Term for the first 15 MW + $10,000/MW above that
	• Performance Assurance is defined to mean collateral in the form of either cash, Letter(s) of Credit, Surety Bond, or a Guaranty (see Section 1.71)
	• Also see Section 5 – Credit and Related Provisions; Section 19 – Events of Default; Section 20 – Early Termination; Section 21 – Cover Costs

Choice of venue	• Greenville County, South Carolina, except for disputes that are subject to arbitration (see Section 26.5) • Section 23 – Disputes and Arbitration
Confidentiality	• Section 16 – Confidentiality • Defines Protected Information as (see Section 16.1): the Agreement; and any proprietary information of the Disclosing Party disclosed in connection with the Agreement that have been clearly marked as confidential or proprietary

Source: DEC and DEP. *Johnson Stipulation Exhibit 5 (Docket Nos. 2021-89-E and 2021-90-E)*. July 23, 2021.

[74] South Carolina Legislature. *South Carolina Code, Title 58, Chapter 41: Renewable Energy Programs.* May 16, 2019.

As noted by the Companies in their joint application, "*[t]he Large QF PPA includes each of the provisions specified by Act 62 and provides for the exclusive purchase and sale of 100% of the output of energy and capacity from a QF facility on a fixed price, fixed term basis*."[75] LEI reviewed the agreement as proposed, and can confirm that the provisions explicitly required under Act No. 62 (namely force majeure, indemnification, choice of venue, and confidentiality) are indeed addressed in the Large QF PPA; Figure 21 above maps each of these provisions to the relevant section/clause in the Companies' form contract, and provides a brief summary where appropriate. Importantly, none of the modifications to the Large QF PPA proposed in the current proceeding affect these sections of the contract, which thus remain unchanged from the version approved by the Commission in the 2019 avoided cost proceeding.

As discussed previously in Section 3.1.5 and Section 3.3, the Companies and other Stipulating Parties propose limited modifications to the Large QF PPA, which are summarized below. These proposed changes have been incorporated in the redline and clean copies of the Large QF PPA submitted as Johnson Stipulation Exhibits 5 and 6, respectively. According to the Companies in their joint application, most of these modifications have been proposed "*to incorporate certain accommodations that have been requested by QFs contracting pursuant to [the Large QF PPA] over the past 18 months*."[76] The proposed updates include:

- modifying the definition of **Change of Control** (Section 1.13 of the Large QF PPA) to "*remove transfers typically done in connection with tax equity financing transactions where the seller retains operational control*";[77]
- adding the definition of **Permitted Transfer** (Section 1.17) to clarify "*certain actions that a QF Seller may take under the Large QF PPA without triggering a Change of Control*."[78] Specifically Section 1.17 now reads: "*"Permitted Transfer" means any direct or indirect transfer of the membership interests in Seller (i) to [fill in lender(s) name(s) as identified in specified lender documents] (collectively, the "Lenders") as a result of the foreclosure by the Lenders of the pledged ownership interests in Seller or any of its direct or indirect parent company or companies provided that after such transfer to the Lenders, the operator of the Facility remains the same as prior to the transfer, or the Lenders engage an operator with at least 2 years of experience in the operation of at least 100 MW of solar energy projects (ii) by the Lenders (upon or after foreclosure by Lenders as specified in (i) above) to a third party, provided that the Seller has, after the third party transfer, in Buyer's commercially reasonable discretion, the technical, engineering, financial, and operational capabilities to perform under this Agreement either directly or by engaging an entity that satisfies such requirements*";[79]

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[75] DEC and DEP. *Joint Application of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (Docket Nos. 2021-89-E and 2021-90-E).* April 22, 2021. P. 17.

[76] Ibid.

[77] DEC and DEP. *Direct Testimony of David B. Johnson on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (Docket Nos. 2021-89-E and 2021-90-E).* May 17, 2021. P. 15.

[78] DEC and DEP. *Stipulation Testimony of David B. Johnson on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (Docket Nos. 2021-89-E and 2021-90-E).* July 23, 2021. P. 6.

[79] DEC and DEP. *Johnson Stipulation Exhibit 5 (Docket Nos. 2021-89-E and 2021-90-E).* July 23, 2021. P. 4.

- extending the **Testing Period** (Section 4.3) day-to-day to "*allow QF Sellers additional time to complete testing where the delay in obtaining a final permit to operate was caused by the Companies and which is not the result of the QF Seller's acts or omissions*";[80] and
- modifying representations and warranties related to the Seller being an **Eligible Commercial Entity** (Section 17.1.9) and **Eligible Contract Participant** (Section 17.1.10) within the Commodity Exchange Act to "*allow QF Sellers additional flexibility for their representation to be effective as of the commercial operation date.*"[81]

LEI's opinion of DEC and DEP's proposed Large QF PPA

The Large QF PPA presented in the Stipulation of Agreement makes limited modifications to the contract approved by the Commission in Order Nos. 2019-818(A) and 2020-315(A) of the 2019 avoided cost proceeding. Importantly, the Large QF PPA as proposed remains compliant with the contractual provisions required under Act No. 62 (namely force majeure, indemnification, choice of venue, and confidentiality).

Upon review of the terms and conditions included in the form contract, LEI believes that the document as proposed continues to be commercially reasonable. As part of this review, LEI compared the Large QF PPA to the terms and conditions included in the Edison Electric Institute's Master Power Purchase & Sale Agreement. This "*model bilateral master agreement*" was drafted and updated in April 2000 through an industry-wide collaboration of more than 80 entities, and contains "*the essential terms governing forward purchases and sales of wholesale electricity*." Although somewhat dated, this master agreement can be viewed as a standardized contract template, which provides a sense of what could be considered as standard industry practice. The terms and conditions included in the Large QF PPA are generally aligned with those of the master agreement.

In addition, the limited changes proposed by the Stipulating Parties and discussed above (including modifications to the Change of Control, Testing Period, and certain representations and warranties, as well as the addition of the Permitted Transfer definition) all act to increase flexibility for QFs contracting under the Large QF PPA. LEI believes the proposed changes do not make fulfillment of the contract more onerous on the part of QFs, and indeed were requested by them, and thus should be approved by the Commission as proposed in the Stipulation.

Source: EEI. *Master Contract.*

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[80] DEC and DEP. *Direct Testimony of David B. Johnson on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (Docket Nos. 2021-89-E and 2021-90-E).* May 17, 2021. P. 16.

[81] Ibid. P. 16.

5.4 Commitment to sell form

As discussed in Section 3.1.6, the NOC Form is "*intended to provide small power producer QFs with a Commission-approved non-contractual option to establish a LEO under PURPA separate from execution of a contractually-binding PPA*."[82] The establishment of a standard NOC Form was specifically required under Act No. 62, with Section 58-41-20(D) of the South Carolina Code stating:

> *A small power producer shall have the right to sell the output of its facility to the electrical utility at the avoided cost rates and pursuant to the power purchase agreement then in effect by delivering an executed notice of commitment to sell form to the electrical utility. The commission shall approve a standard notice of commitment to sell form to be used for this purpose that provides the small power producer a reasonable period of time from its submittal of the form to execute a power purchase agreement. In no event, however, shall the small power producer, as a condition of preserving the pricing and terms and conditions established by its submittal of an executed commitment to sell form to the electrical utility, be required to execute a power purchase agreement prior to receipt of a final interconnection agreement from the electrical utility.*[83]

The Companies' NOC Form is a brief 5-page form that sets out the following items, among others:

- the **name**, **address**, and **contact information** for the QF;
- **site location**; and
- the **delivery term** (either two, five, or ten years).

The NOC Form also sets out the following terms, among others:

- requires the QF to achieve **commercial operation** and commence delivery of its output to DEC/DEP within 365 days of submitting the notice – otherwise the NOC shall automatically terminate, subject to certain exceptions;
- clarifies that if the NOC is terminated, the QF shall only be eligible for an as-available rate for a two-year period, after which point the QF may elect to submit a new NOC Form;
- allows the QF to terminate the NOC if, after it has received a System Impact Study Report from DEC/DEP, the estimated interconnection facilities and system upgrades exceed $75,000/MW AC.

Redline and clean copies of DEC and DEP's proposed NOC Form were submitted by Mr. Johnson in Johnson DEC/DEP Exhibits 7 and 8, respectively. As noted by Mr. Johnson in his direct testimony, the Companies are proposing minimal changes to the NOC Form relative to the version approved by the Commission in the 2019 avoided cost proceeding. Specifically, "*[t]he only*

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[82] DEC and DEP. *Joint Application of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (Docket Nos. 2021-89-E and 2021-90-E)*. April 22, 2021. P. 20.

[83] South Carolina Legislature. *South Carolina Code, Title 58, Chapter 41: Renewable Energy Programs.* May 16, 2019.

changes that have been made are to remove the option to submit the Notice of Commitment Form by mail, recognizing that all documents are now submitted by email. The need for this change became especially apparent in the Covid-19 pandemic."[84]

LEI's opinion of DEC and DEP's proposed NOC Form

As noted in Mr. Johnson's direct testimony, the only change made to the NOC Form has been to remove the options to deliver the executed document via certified mail, courier, or hand delivery, and instead requires submission by email only. LEI believes that this is a reasonable change, as it does not make the submission process unnecessarily onerous for eligible QFs, and indeed may make it easier.

Given the limited update made to the NOC Form relative to the version approved in the 2019 avoided cost proceeding, which does not materially alter the document, or the terms and conditions contained therein, LEI believes that the Commission should approve the NOC Form as proposed by DEC and DEP.

[84] DEC and DEP. *Direct Testimony of David B. Johnson on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (Docket Nos. 2021-89-E and 2021-90-E).* May 17, 2021. P. 21.

6 Concluding remarks

LEI has carefully reviewed the evidence entered into the hearing record and conducted its own independent analysis of DEC and DEP's avoided cost methodology, rates, and terms and conditions as proposed in the Stipulation of Agreement. LEI discusses several observations made through its review of the filings in Section 6.1 below, which is followed in Section 6.2 by a summary of LEI's final opinion consistent with the language of the law.

6.1 Observations regarding the filings

While LEI recommends accepting the settlement proposal for reasons discussed elsewhere in this report, LEI nonetheless has several observations which may be useful in future iterations of these proceedings. These observations are discussed in the subsections that follow.

6.1.1 Synchronizing date of consultant engagement with procedural calendar

The number of days between the date LEI was able to execute an engagement letter (August 3rd, 2021) and the due date of the report (August 23rd, 2021) equaled 20 days. As data requests ("DRs") require allowing 20 days for a response, pursuant to Section 103-833 of the South Carolina Code of State Regulations,[85] LEI was unable to submit data requests related to the Duke company filings with enough time to receive and adequately review responses. While in light of the Stipulation, LEI does not believe that its inability to submit DRs impacted its ultimate conclusions, future proceedings would benefit from timelines that enable DRs on all filings.

6.1.2 Evolution of the peaker method

A number of developments are likely to influence future applications of the peaker method to determine avoided costs. Battery costs are falling rapidly, and although unlikely to be competitive with existing natural gas-fired technologies for avoided cost calculations in the next five years, they may be by 2030. Convergence may accelerate should carbon neutrality be mandated. Furthermore, if at some point in the future the proposed Southeast Energy Exchange Market were to develop into something more closely resembling other US independent system operators ("ISOs"), avoided cost calculations may need to incorporate consideration of wholesale market prices and forwards.

6.1.3 Minimizing redactions

While LEI recognizes that confidential information can be reviewed if a confidentiality agreement is signed, this process is nonetheless a barrier to the average ratepayer being able to understand the basis for the calculations underlying the proposed avoided costs. For example, in the current proceeding, Snider DEC and DEP Exhibits 1 were designated confidential and filed under seal, even though they outlined the supporting calculations used to derive the proposed avoided cost rates. LEI was struck by the number of redactions in the public versions of these exhibits (see

[85] South Carolina Legislature. *South Carolina Code of State Regulations, 103-833: Written Interrogatories and Request for Production of Documents and Things.* April 27, 2007.

Figure 22 below, which captures the redacted portions of the capacity cost calculations), and questions whether the inputs are truly commercially sensitive. This is especially the case given that they can be replicated with use of reasonable publicly available proxies. LEI does not believe that greater clarity with regards to assumptions such as the discount for economies of scale would disadvantage the Companies in negotiations with vendors, and recommends that the Companies seek to limit such redactions in the future.

Figure 22. Examples of redacted calculations in DEC and DEP's filings

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DUKE ENERGY CAROLINAS, LLC

Annual Avoided Capacity Costs

	Distribution				Transmission			
Year	CT Cost Annual Capacity (CT) Cost (1) (2021 $000s)	Capacity (CT) Cost (Nominal $000s)	FOM Annual Capacity (FOM Cost(1) (2021 $000s)	Capacity (FOM) Cost Nominal $000s)	CT Cost Annual Capacity (CT) Cost (1) (2021 $000s)	Capacity (CT) Cost (Nominal $000s	Capacity (FOM Cost(1) (2021 $000s)	Capacity (FOM) Cost (Nominal $000s)
2022	$0	$0	$0	$0	$0	$0	$0	$0
2023	$0	$0	$0	$0	$0	$0	$0	$0
2024	$0	$0	$0	$0	$0	$0	$0	$0
2025	$0	$0	$0	$0	$0	$0	$0	$0
2026	[redacted]							
2027								
2028								
2029								
2030								
2031								

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DUKE ENERGY CAROLINAS, LLC

Capacity Cost for Determination
of Capacity Credits

(2021 $000s)

	Distribution		Transmission	
	CT Cost	FOM (6)	CT Cost	FOM (6)
1. Installed Combustion Turbine Cost (Note 1)	[redacted]			
2. Combustion Turbine Fixed Charge Rate (Note 2)	10.204%		10.204%	
3. Annual Combustion Turbine Carrying Cost (L1*L2)	[redacted]			
4. General Plant Factor (Note 4)	3.62%		3.62%	
5. Adjusted Annual Combustion Turbine Carrying Cost	[redacted]			
6. Combustion Turbine Fixed O&M Expenses	[redacted]			
7. Working Capital Factor (Note 3)		1.0353		1.0353
8. Subtotal (L5+(L6*L7))	[redacted]			
9. Performance Adjustment Factor	1.07	1.07	1.07	1.07
10. Marginal Loss Factor (Note 5)	1.0289	1.0289	1.0011	1.0011
11. Annual Capacity Cost (L8*L9*L10)	[redacted]			

Source: DEC and DEP. *Snider DEC Exhibit 1, Snider DEP Exhibit 1 (Docket Nos. 2021-89-E and 2021-90-E).* May 17, 2021.

6.1.4 Sophistication of modeling

More modeling is not necessarily better modeling, and the results of any modeling exercise are the product of the assumptions used. However, the description of the approach in the application is remarkably simplistic when compared against the modeling approaches used in the IRPs or in the reserve margin studies.

As discussed previously and as described by Mr. Snider in his direct testimony, the production cost modeling conducted by the Companies to determine avoided energy costs involves simulating two cases – "*[t]he first simulation uses IRP models and current market assumptions to establish the "base case" of the estimated variable production costs over the period. The second simulation is identical to the first but adds a hypothetical 100 MW of no-cost generation to the utility's generating fleet, which is available to the system in every hour of the ten-year period*."[86] DEC and DEP in their filings do not appear to disclose whether any additional scenarios or sensitivities were run as part of this modeling exercise.

Use of a single base case, as opposed to using multiple scenarios or a Monte Carlo approach, may underestimate the sensitivity of the results to extreme events. While LEI is not of the view that thousands of model runs are necessary to develop a reasonable conclusion, in LEI's experience a case-based approach can yield insights that relying solely on a base case may not.

6.1.5 Seasonal value of capacity

Given that there is a settlement that involves diverse stakeholders, LEI is not recommending different seasonal capacity values in this case. However, while LEI acknowledges that saturation by solar capacity at particular times of day reduces the value of additional capacity, LEI is not convinced that the value of all types of capacity falls to zero in all circumstances. Capacity mechanisms in organized wholesale markets have moved away from vertical demand curves in which the value of capacity falls to zero immediately upon reaching some target reserve margin. Even where the additional capacity is solar, each additional increment guards to a certain extent against outages at other solar facilities. If the additional increment of capacity is dispatchable, it may have greater value. LEI believes that any recommendation of a capacity value of zero in any specific period needs to be carefully examined in future proceedings, as well as whether there should be a differentiation between dispatchable and non-dispatchable capacity.

6.1.6 Holistic consideration of risk

Many discussions of avoided cost focus narrowly on the cost to consumers from additional contracts, and concerns regarding potential stranded costs – i.e., costs for capacity that is not needed in the future. But the goal of "*reduc[ing] the risk placed on the using and consuming public*"[87] may require a wider focus. After a period of historically low fuel prices, robust reserve margins, and falling costs for some types of capacity, it is possible that market conditions may have reached

[86] DEC and DEP. *Direct Testimony of Glen A. Snider on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (Docket Nos. 2021-89-E and 2021-90-E)*. May 17, 2021. P. 25.

[87] South Carolina Legislature. *South Carolina Code, Title 58, Chapter 41: Renewable Energy Programs.* May 16, 2019.

a trough. At the same time, recent extreme weather events have tested the resiliency of the electric power system.

Consideration of the date of first need may also need to incorporate the risk of reduced reliability (what if the utility's date of first need is wrong?) resulting in a risk of under-procurement. Furthermore, while in a falling cost environment, regulators may fear locking customers into contracts too early in the cost curve, in a period of potentially increasing inflation, shorter term PPAs may not protect consumers from rising costs. Availability of QFs also provides a degree of competition to utilities that otherwise have minimal exposure to it, and provides diversity of ownership and operation. Utilities theoretically have a generalized incentive to understate avoided costs and need in PURPA proceedings; however, participation by a wide range of stakeholders in the proposed Stipulation gives LEI confidence that in this case an appropriate balance has been struck.

6.1.7 Use of an Administrative/Seller Charge

While the size of the Administrative/Seller Charge is relatively small, it should be reviewed in subsequent proceedings to determine if it is calculated in a fashion that is non-discriminatory to small power producers. If the utility does not burden its own generation with a similar charge, then such a charge should not be levied against QFs.

6.1.8 Value of ancillary services

Through the definition of avoided costs established in Act No. 62, which includes costs related to energy and capacity, utilities are also able to consider ancillary services as a component of their avoided cost methodologies.[88] The avoided costs as presented in the current proceeding do not address compensation for avoided ancillary services. While the Solar Integration Services Charge included in DEC and DEP's Schedule PP (standard offer) tariff addresses ancillary services costs the Companies face as a result of integrating increasing levels of solar QF generation, there is no corresponding calculation of what the Companies would pay to a QF which could offer ancillary services.

While it is currently unlikely that many, if any, of the QFs availing themselves of the subject tariffs would have the requisite capabilities to provide ancillary services, that may change as technology improves and battery costs fall. Although results from organized markets such as PJM suggest that the resulting revenues may be small, for some resources the additional payments could impact breakeven economics.

[88] Per Act No. 62, the Commission shall ensure that "*each electrical utility's avoided cost methodology fairly accounts for costs avoided by the electrical utility or incurred by the electrical utility, including, but not limited to, energy, capacity, **and ancillary services** provided by or consumed by small power producers*" [emphasis added] (Source: South Carolina Legislature. *South Carolina Code, Title 58, Chapter 41: Renewable Energy Programs.* May 16, 2019)

6.2 LEI's overall opinion consistent with directives from Act No. 62

As initially presented in Section 2.2, Act No. 62 directs the Commission to ensure the following in order to preserve the nondiscriminatory treatment of small power producers:

1. "*rates for the purchase of energy and capacity fully and accurately reflect the electrical utility's avoided costs*";
2. "*power purchase agreements, including terms and conditions, are commercially reasonable and consistent with regulations and orders promulgated by the Federal Energy Regulatory Commission implementing PURPA*"; and
3. "*each electrical utility's avoided cost methodology fairly accounts for costs avoided by the electrical utility or incurred by the electrical utility, including, but not limited to, energy, capacity, and ancillary services provided by or consumed by small power producers including those utilizing energy storage equipment. Avoided cost methodologies approved by the commission may account for differences in costs avoided based on the geographic location and resource type of a small power producer's qualifying small power production facility.*"[89]

Along with assuring customers do not overpay for QF power, these can be thought of as among the Commission' key objectives in the avoided cost proceedings. LEI does not believe the rates proposed in the stipulation will result in customers overpaying for power. LEI provides its overall opinion of DEC and DEP's 2021 avoided cost proceeding in the textbox below, which pulls together the conclusions reached in each of the previous sections of this report, and assesses these against the three objectives outlined above.

LEI's overall opinion of DEC and DEP's 2021 avoided cost proceeding

1. ***The proposed Schedule PP and Large QF tariffs accurately reflect DEC and DEP's avoided costs to the extent allowed by the modeling***

   LEI believes that analyses such as those performed to calculate avoided costs may sometimes engage in fallacies of misplaced precision. While it is important that modeling be thorough, ultimately all the assumptions used in the modeling exist within a band of uncertainty. Just as the term "zone of reasonableness" is sometimes used in the discussion of appropriate allowed returns in regulatory proceedings, LEI believes a similar zone of reasonableness needs to be considered in the context of avoided cost proceedings.

   While LEI's calculations may have resulted in different recommendations, the numbers proposed are within 5% of those LEI developed. LEI can envision a set of reasonable assumptions which would result in the proposed rates.

(continued…)

[89] South Carolina Legislature. *South Carolina Code, Title 58, Chapter 41: Renewable Energy Programs.* May 16, 2019.

2. ***The terms and conditions included in the proposed Standard Offer PPA, Standard Offer Terms and Conditions, Large QF PPA, and NOC Form are commercially reasonable and remain consistent with PURPA***

   The contract documents as proposed in the Stipulation are largely unchanged and remain consistent with the versions previously approved by the Commission in the 2019 avoided cost proceeding. The Stipulating Parties propose the most changes to the Large QF PPA (including modifications to the Change of Control, Testing Period, and certain representations and warranties, as well as the addition of the Permitted Transfer definition), all of which act to increase flexibility for QFs. LEI believes the proposed changes do not make fulfillment of the agreements more onerous on the part of QFs, and indeed were requested by them in some instances.

   Given these limited proposed modifications, it is LEI's view that the Commission should continue to find the contract documents commercially reasonable and consistent with PURPA, and thus should approve the documents as proposed in the Stipulation.

3. ***The proposed avoided cost methodology fairly accounts for DEC and DEP's avoided costs***

   The Companies propose to continue using the same peaker methodology that was used and approved in the 2019 avoided cost proceeding. As part of its analysis, LEI reviewed the Companies' approach to calculating avoided costs and does not take issue with the methodology or resulting avoided cost estimates. LEI further agrees with the modification proposed in the Stipulation, which adopts the seasonal allocation for DEC's capacity payments as recommended by ORS witness, Brian Horii. This modification ensures capacity costs are allocated in a way that better reflects expected system needs.

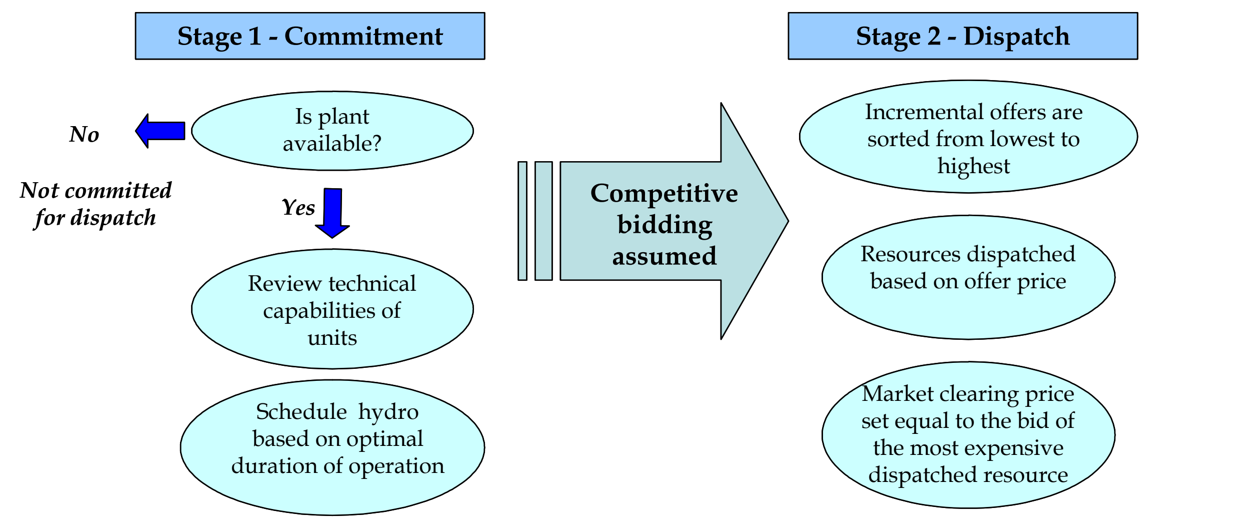
For the reasons stated above, LEI recommends that the Commission approve the proposed Stipulation. In its evaluation of the evidence included in the hearing record, LEI places weight on the participation of diverse stakeholders in the negotiations that ultimately resulted in the proposed Stipulation. Because the Stipulation includes organizations representing the public interest as well as the interests of developers, even if participation was not comprehensive, it nonetheless suggests that the settlement is balanced.

7 Appendix A: Overview of POOLMod forecasting methodology

For the wholesale energy prices outlook, we employed our proprietary simulation model, POOLMod, as the foundation for our electricity price forecast. POOLMod simulates the dispatch of generating resources in the market subject to least cost dispatch principles to meet projected hourly load and technical assumptions on generation operating capacity and availability of transmission.

POOLMod consists of a number of key algorithms, such as maintenance scheduling, assignment of stochastic forced outages, hydro shadow pricing, commitment, and dispatch. The first stage of analysis requires the development of an availability schedule for system resources. First, POOLMod determines a 'near optimal' maintenance schedule on an annual basis, accounting for the need to preserve regional reserve margins across the year and a reasonable baseload, mid-merit, and peaking capacity mix. Then, POOLMod allocates forced (unplanned) outages randomly across the year based on the forced outage rate specified for each resource.

Figure 23. POOLMod's two-stage process



POOLMod next commits and dispatches plants on a daily basis. Commitment is based on the schedule of available plants net of maintenance, and takes into consideration the technical requirements of the units (such as start/stop capabilities, start costs (if any), and minimum on and off times). During the commitment procedure, hydro resources are scheduled according to the optimal duration of operation in the scheduled day. They are then given a shadow price just below the commitment price of the resource that would otherwise operate at that same schedule (i.e., the resource they are displacing).

In addition, POOLMod is a transportation-based model, giving it the ability to take into account thermal limits on the transmission network.

8 Appendix B: Works cited

CCEBA. *Petition to Intervene (Docket Nos. 2021-89-E and 2021-90-E).* April 12, 2021.

Chugach Electric Association, Inc. *Eklutna Power Purchase Agreement.* December 2018.

DEC and DEP. *Snider DEC/DEP Exhibit 3 (Docket Nos. 2021-89-E and 2021-90-E).* May 17, 2021.

DEC and DEP. *Amended Partial Settlement Agreement (Docket Nos. 2019-185-E and 2019-186-E).* July 29, 2021.

DEC and DEP. *Direct Testimony of David B. Johnson on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (Docket Nos. 2021-89-E and 2021-90-E).* May 17, 2021.

DEC and DEP. *Direct Testimony of Glen A. Snider on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (Docket Nos. 2021-89-E and 2021-90-E).* May 17, 2021.

DEC and DEP. *Johnson DEC Exhibit 4, Johnson DEP Exhibit 4 (Docket Nos. 2021-89-E and 2021-90-E).* May 17, 2021.

DEC and DEP. *Johnson DEC Exhibits 1 and 2, Johnson DEP Exhibits 1 and 2 (Docket Nos. 2021-89-E and 2021-90-E).* May 17, 2021.

DEC and DEP. *Johnson Stipulation Exhibit 2 (Docket Nos. 2021-89-E and 2021-90-E).* July 23, 2021.

DEC and DEP. *Johnson Stipulation Exhibit 5 (Docket Nos. 2021-89-E and 2021-90-E).* July 23, 2021.

DEC and DEP. *Joint Application of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (Docket Nos. 2021-89-E and 2021-90-E).* April 22, 2021.

DEC and DEP. *Snider DEC Exhibit 1, Snider DEP Exhibit 1 (Docket Nos. 2021-89-E and 2021-90-E).* May 17, 2021.

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ORS. *Direct Testimony and Exhibits of Brian Horii (Docket Nos. 2021-89-E and 2021-90-E)*. June 11, 2021.

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SC PSC. *Statements of Award (Contract Nos. 4400026690 and 4400026691).* July 28, 2021.

South Carolina Legislature. *South Carolina Code of State Regulations, 103-833: Written Interrogatories and Request for Production of Documents and Things.* April 27, 2007.

South Carolina Legislature. *South Carolina Code, Title 58, Chapter 41: Renewable Energy Programs.* May 16, 2019.

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9 Appendix C: LEI's qualifications

9.1 About the expert

AJ Goulding, President of LEI, has over thirty years of experience in the energy sector, having advised clients in North America, Europe, Asia, and the Middle East.

AJ has direct experience with calculation of levelized costs of new utility investments, both from the perspective of the utility and from investors. AJ has led and completed many of LEI's regulatory engagements related to utility proceedings, including testifying in US proceedings and before the Ontario Energy Board, the Alberta Utilities Commission, and the Canada Energy Regulator, among other regulators. Through these engagements, AJ has directed and authored independent reports to commissions, prepared discovery questions, responded to interrogatories from parties, authored rebuttals, provided cross-examination of expert witnesses, and provided oral testimony.

In addition to his work at LEI, AJ serves as an Adjunct Associate Professor at Columbia University, where he teaches a graduate course on electricity market design and regulatory economics, while also supervising graduate workshops.

9.2 Background on the firm

LEI is a US owned and operated global economic, financial, and strategic advisory professional services firm specializing in energy and infrastructure. The firm's areas of expertise are briefly described in Figure 24 below.

Figure 24. LEI's areas of expertise

LEI combines detailed understanding of specific network and commodity industries, such as electricity generation, transmission, and distribution, with sophisticated analysis and a suite of proprietary quantitative models to produce reliable and comprehensible results.

The firm had its start in 1996 during the initial round of liberalization and unbundling of electricity, gas, and water companies and markets in the US and overseas. Since then, LEI has advised regulators, private sector clients, market institutions, and governments on policy initiatives, market and tariff design, asset valuation, market power, and strategy in markets worldwide. Across North America specifically, LEI has advised regulatory and policy bodies in over twenty states and provinces, and worked for industry clients in a further eight states, territories, and provinces in engagements involving testifying before or facing government entities (see Figure 25). LEI's ability to comment on matters related to avoided cost calculations rest on a foundation of prior projects, including the design, application, and utilization of levelized cost of electricity ("LCOE") calculations; work for state regulators; expert testimony experience (both written and oral); expertise conducting PPA reviews and negotiations; and projects focused on the unique characteristics of renewably energy resources, including solar.

Figure 25. Selected LEI North American regulatory and policy engagements